State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities

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Executive Summary

Berkeley Lab published a report in 2016 that discussed two approaches to performance-based regulation (PBR) of electric utilities: multiyear rate plans (MRPs) and performance incentive mechanisms (PIMs).[1] The authors described these approaches at a high level and in the context of growing levels of demand-side management (DSM), distributed generation and other distributed energy resources (DERs).

This report presents a more in-depth analysis of the multiyear rate plan approach to PBR for electric utilities, applicable to both vertically integrated and restructured states. The report is aimed primarily at state utility regulators and stakeholders in the state regulatory process. The approach also provides ideas on how to streamline oversight of public power utilities and rural electric cooperatives by their governing boards.

We discuss the rationale for MRPs and their usefulness under modern business conditions. We then explain critical plan design issues and challenges and present results from numerical research that considers the extra incentive power achieved by MRPs with different plan provisions. Next, the report presents several case studies of utilities that have operated under formal MRPs or, for various reasons, have stayed out of rate cases for more than a decade. In these studies we consider the effect of MRPs and rate case frequency on utility cost, reliability and other performance dimensions. Appendices present further information on MRP plan design and some details of the technical work.

What Are MRPs?

MRPs are a comprehensive approach to PBR designed to strengthen general incentives for good utility performance. Two key provisions of MRPs strengthen cost containment incentives and streamline regulation:

1. A rate case moratorium reduces the frequency of rate cases, typically to once every four or five years.

2. An attrition relief mechanism (ARM) escalates rates or revenue between rate cases to address cost pressures such as inflation and growth in number of customers independently of the utility's own cost.

Loosening the link between its own cost and revenue gives a utility an operating environment more like that which competitive markets experience.

Most MRPs feature a performance metric system that includes some PIMs. These PIMs provide awards or penalties, or both, for performance in targeted areas. PIMs are most commonly used in MRPs to strengthen incentives for utilities to maintain or improve reliability and customer service quality. Some plans also include earnings sharing mechanisms, efficiency carryover mechanisms and marketing flexibility.

Provisions are often added to plans to strengthen utility incentives for DSM. For example, utility expenditures on DSM programs are usually tracked, and PIMs can be added to reward utilities for successful DSM programs. Revenue decoupling can mitigate a utility's incentive to boost retail sales and reduce risks of revenue losses from rate designs that encourage DSM.

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[1] Lowry and Woolf (2016).

How Prevalent Is This Approach?

MRPs were first widely used in the United States in the 1980s to regulate railroads and telecommunications carriers, industries beset by rising competition. Early adopters of MRPs in the U.S. electric utility industry included California and several northeastern states. Use of MRPs has recently grown among vertically integrated electric utilities in diverse states that include Arizona, Georgia and Washington. Greater use of MRPs for power distributors has been slowed by their requests for accelerated system modernization, which complicate plan design. MRPs are much more common for electric utilities in Canada and countries overseas. The impetus for adopting MRPs in these countries has often come from policymakers rather than utilities.

What Is the Rationale for These Plans?

America's investor-owned electric utility industry was largely built under cost of service regulation (COSR). This regulatory system traditionally adjusted rates that compensate utilities for costs of capital, labor and materials only in general rate cases. The scope of costs eligible for tracker treatment, which expedites cost recovery, has gradually enlarged and sometimes includes capital costs as well as energy expenditures.

The efficacy of COSR varies with external business conditions. When conditions favor utilities (e.g., are conducive to realizing at least the target rate of return), rate cases are infrequent. Performance incentives are then strong and the cost of regulation is quite reasonable. When conditions are less favorable, rate cases are more frequent and more costs are tracked. Performance incentives can then be weak and regulatory cost can be high. These attributes of COSR are worrisome because business conditions today are often less favorable to utilities than in the past.

MRPs are a different approach to regulation that is especially appealing when the alternative is frequent rate cases or expansive cost trackers. The regulatory process is streamlined and better utility performance can be encouraged due to stronger performance incentives and increased operating flexibility. Benefits of better performance can be shared with customers. Recent advances in MRPs such as efficiency carryover mechanisms and statistical benchmarking can "turbocharge" their incentive power and ensure benefits for customers.

What Are Some Disadvantages of MRPs?

MRPs are complex, and their adoption can involve extensive change to the regulatory system. It can be challenging to design plans that strengthen incentives without undue risk and share benefits fairly between utilities and their customers. Some kinds of business conditions (e.g., brisk inflation and declining average use) have proven easier to address using MRPs than others (e.g., capital spending surges). MRPs can invite strategic behavior and controversies over plan design.

Case Studies

This report discusses six case studies of utilities operating under MRPs:

1. Central Maine Power operated under a sequence of MRPs from 1996 to 2013. The plans afforded the company unusual marketing flexibility which it used to develop special contracts with large-volume customers. These contracts helped the company retain their contributions to fixed costs of the system, for the benefit of all customers.

2. California has the nation’s longest history with MRPs for retail services of electric utilities. The Public Utilities Commission has limited rate case frequency and staggered plan terms to avoid simultaneous rate cases. Plan provisions have provided strong incentives for utilities to embrace DSM.
3. New York has regulated electric utilities using MRPs since the 1990s. The state’s Reforming the Energy Vision proceeding has considered how rate plans should evolve to regulate the “utility of the future.”
4. MidAmerican Energy operated under a rate freeze in Iowa from 1997 to 2013. This freeze extended to charges for energy procured as well as for capital, labor and materials.
5. Ontario, Canada, has used MRPs to regulate the dozens of power distributors since the late 1990s. Capital spending surges have posed special plan design challenges. Innovations in Ontario regulation also include incentive-compatible menus and extensive use of benchmarking.
6. Great Britain also has a long history with MRP regulation. The current “RIIO” approach to regulation of energy utilities there has attracted the attention of many North American regulators.

Impact on Cost Performance

This report also addresses the impact of MRPs (and, more generally, rate case frequency) on utility cost performance using two analytical tools: incentive power analysis and empirical research on utility productivity trends. An Incentive Power Model uses numerical analysis to assess the incentive impact of alternative stylized regulatory systems. For North American case studies, we compared productivity trends of utilities operating under MRPs to U.S. norms. We also considered productivity trends of utilities that operated under unusually frequent and infrequent rate cases.

Both lines of research suggest that the frequency of rate cases can materially affect utility cost performance. For example, the multifactor productivity (MFP) growth of the electric, gas and sanitary sector of the U.S. economy was materially slower than that of the economy as a whole from 1974 to 1985, when rate cases were frequent due in part to adverse business conditions, than in the early postwar period, when favorable business conditions encouraged less frequent rate cases. We also found that the MFP growth of utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the full sample norm. Cumulative cost savings of 3 percent to 10 percent after 10 years appear achievable under MRPs.

Conclusions

The case studies and incentive power and productivity research presented in this report have important implications. First, utility performance and regulatory cost should be on the radar screen of U.S. regulators, consumer groups and utility managers. Our research shows that key business conditions facing utilities today are less favorable than in the decades before 1973 when COSR worked well and was becoming a tradition. Today’s conditions encourage more frequent rate cases and more expansive cost trackers. MRPs can produce material improvements in utility performance which can slow growth in customer bills and bolster utility earnings.

Notwithstanding the potential benefits of MRPs, they are still not used in most American states. COSR is well established and there are many accomplished practitioners. It can be difficult to design MRPs that generate strong utility performance incentives without undue risk, and that share benefits of better performance fairly with customers. MRPs invite strategic behavior and controversies over plan design. Continuing innovation of COSR will occur, and this will slow diffusion of MRPs.

However, MRPs are also evolving and remedies to problems encountered in early plans have been developed. MRPs are well suited for addressing conditions expected in coming years, such as rising input price inflation and DER penetration and increased need for marketing flexibility. For these and other reasons, we foresee expanded use of MRPs in U.S. electric utility regulation in coming years.

Acknowledgments

The work described in this study was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, Transmission Permitting and Technical Assistance Division, and the Office of Energy Efficiency and Renewable Energy, Solar Energy Technologies Office, under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231, DOE Grid Modernization Initiative Task 1.4.29 – Future Electric Utility Regulation.

We thank Larry Mansueti, Guohui Yuan and Elaine Ulrich (DOE) for their support of this work. For reviewing drafts of this report and providing comments, we thank Sonia Aggarwal (Energy Innovation), Peter Cappers (Berkeley Lab), Steven Corneli, Asa Hopkins (Synapse Energy Economics), Ronald Lehr, Larry Mansueti (DOE), Andy Satchwell (Berkeley Lab) and Jay Shepherd (Energy Law).

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Glossary of Terms

Attrition Relief Mechanism (ARM): An essential provision of multiyear rate plans that automatically adjusts allowed rates or revenues to address cost pressures without closely tracking the utility's own cost. Methods used to design ARMs include forecasts and indexation to quantifiable business conditions such as inflation and growth in the number of customers served.

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 sometimes also include charges for costs of energy inputs like fuel and purchased power, but trackers usually adjust rates so these costs are recovered more exactly.

Capex: Capital expenditures

Cost Tracker: A mechanism providing expedited recovery of targeted costs. An account typically tracks costs that are eligible for recovery. These costs are then typically recovered via rate riders. Tracker treatment was traditionally limited to costs that are large, volatile and largely beyond the control of the utility. The scope of costs eligible for tracking has widened over time. In multiyear rate plans, trackers have been used for costs that are difficult for the ARM to address.

Earnings Sharing Mechanism (ESM): An ESM shares surplus or deficit earnings, or both, between utilities and customers, which result when the rate of return on equity deviates from its commission-approved target. ESMs often have dead bands in which earnings variances are not shared.

Efficiency Carryover Mechanism: A mechanism that allows for a share of lasting performance gains (or losses) to be kept by the utility for a set period of time when a multiyear rate plan expires.

Formula Rate Plan: An approach to ratemaking that uses cost of service formulas to cause a utility's revenue to track its own cost of service closely. This is sometimes accomplished with an earnings true-up mechanism that adjusts rates automatically to eliminate variances between a company's actual and target rate of return on equity. Review of the cost of service may be streamlined.

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

Marketing/Pricing Flexibility: Flexibility afforded to utilities to fashion rates and other terms of service in selected markets. Marketing flexibility is typically accomplished via light-handed regulation of rates and services with certain attributes. 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 discourage predation and cross-subsidization.

Multiyear Rate Plan (MRP): A common approach to performance-based regulation that typically features a rate case moratorium for several years, an ARM, and performance incentive mechanisms for service quality.

Off-ramp Mechanism: An MRP option that permits reconsideration of a multiyear rate plan under prespecified conditions such as an extremely high or low rate of return on equity.

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

Performance Incentive Mechanism (PIM): A popular form of performance-based regulation that links utility revenue or earnings to performance in targeted areas. Most PIMs involve metrics, targets (sometimes called *outcomes*) and financial incentives (rewards and penalties). Service quality and demand-side management are common focuses.

Productivity: The efficiency with which a utility converts inputs to outputs, commonly measured by productivity indexes. Labor, operation and maintenance, capital and multifactor productivity are commonly measured. Industry productivity trends are often used in the design of ARMs.

Rate Base: A utility's total "used and useful" plant in service, at original cost, minus accumulated depreciation and deferred income taxes. Rate base includes "working capital" — cash the utility must have available to meet the current cost of operations given the lag between customers receiving electric service and when they pay their electric bills. Regulators may allow other adjustments.

Rate Rider: An explicit mechanism outlined on tariff sheets to allow a utility to receive supplemental revenue adjustments.

Revenue Decoupling Mechanism: A mechanism that periodically adjusts rates to ensure that actual revenue closely tracks allowed revenue. Decoupling can reduce or eliminate the "throughput incentive" that can cause utilities to resist demand-side management.

RIIO: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO involves MRPs that include relatively long rate case moratoria (e.g., eight years), a forecast-based ARM, and an extensive set of performance incentive mechanisms.

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

X Factor (Productivity Factor): A term in a rate or revenue cap index that reflects the impact of productivity growth on cost growth. It may also incorporate stretch factors and adjustments for other considerations such as the inaccuracy of the inflation measure.

Z Factor: A term in a rate or revenue cap index that permits rate adjustments for the financial impact of miscellaneous events (e.g., severe storms) that are beyond the utility's control.

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1.0 Introduction

The electric utility industry has made significant contributions to the success of the U.S. economy over the years. Rates and service quality of electric utilities affect both household welfare and the competitiveness of business and industry. The large role played by many U.S. utilities in power generation magnifies their importance.

Utilities today must contain cost growth at a time when many need to modernize aging systems. Major changes are occurring in technologies, customer preferences, load growth, competitive challenges, and federal and state policies and regulations. Most electric utility facilities in the United States are investor-owned and subject to rate and service regulation by state public utility commissions. Regulatory systems under which these utilities operate affect their performance and ability to meet challenges.

Multiyear rate plans have some advantages over traditional rate regulation in today's business environment. This is a form of performance-based regulation (PBR) that suspends general rate cases for several years. Revenue growth between rate cases is to some degree predetermined and independent of a utility's own cost. Better utility performance can sometimes be achieved under MRPs while achieving lower regulatory costs.[2] Benefits can be shared between utilities and their customers. However, plans are complex and their adoption can involve sizable changes in the regulatory system. Designing plans that stimulate performance without undue risk and share benefits fairly can be challenging.

Berkeley Lab prepared a report on PBR in 1995, when it was just beginning.[3] The study appraised some approved PBR plans using an "incentive power index." Thoughtful commentary on PBR included prescient discussion of revenue decoupling, which is now widely used in utility regulation. In 2016, Berkeley Lab published a report comparing MRPs to another popular approach to PBR — targeted performance incentive mechanisms — in the context of growing levels of distributed energy resources.[4] The report focused on advantages and disadvantages from utility shareholders' and customers' perspectives.[5]

This report takes a closer look at MRPs for electric utilities:

- how and where they have been applied to electric utilities in the United States and other countries;
- key plan design and implementation issues;
- metrics used to evaluate and incentivize utility performance; and
- successes, failures and lessons learned.

The focus is on retail services, such as power supply, distribution and customer care, which are regulated by states.

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[2] The impact of PBR on the performance of cooperative and publicly owned utilities is not well understood. However, PBR provides ideas on how to streamline regulation of these utilities. Numerous publicly owned utilities in other countries have operated under PBR.
[3] Comnes et al. (1995).
[4] The report explained that energy efficiency, demand response, and distributed generation and storage can help contain costs of meeting America's energy needs, but can reduce utility earnings.
[5] Lowry and Woolf (2016).

While the authors of the 1995 Berkeley Lab study anticipated restructuring of retail U.S. power markets, vertically integrated electric utilities (VIEUs) still serve retail customers in many states. This report thus considers the situations of VIEUs as well as those of the utility distribution companies (UDCs) that serve regions with restructured retail power markets. The report also provides results from an incentive power model and research on trends in the productivity with which utilities provide their services.

Section 2 of this report provides an introduction to MRPs. Section 3 considers rationales for MRPs and their suitability for electric utilities today. Section 4 drills down into important issues in MRP design. Section 5 discusses results of our research on the incentive power of alternative regulatory systems. Section 6 presents several case studies, and Section 7 discusses lessons learned. Two appendices discuss some topics in greater detail.

2.0 Multiyear Rate Plans

2.1 The Basic Idea

PBR is an approach to utility regulation designed to encourage good performance using strong performance incentives. Multiyear rate plans are a common form of PBR around the world. Berkeley Lab's 2016 report discussed basic features of these plans.[6] General rate cases are typically held every four or five years. Between rate cases, an attrition relief mechanism (ARM) permits revenue (or rates) to grow in the face of cost pressures, without linking relief to a utility's *specific* costs.[7] Some costs may be addressed separately using cost trackers and associated rate riders.

Following is a generic formula for revenue escalation in a multiyear rate plan:

$$growth\ Revenue = growth\ ARM + Y + Z. \qquad [1]$$

The "Y factor" indicates the revenue adjustment for costs, such as fuel and purchased power expenses, which are chosen in advance for tracking treatment. The "Z factor" indicates the revenue adjustment for miscellaneous changes in cost which may occasionally be accorded tracker treatment. The Z factor may address cost changes due to miscellaneous factors outside utility control, such as government mandates (e.g., facility undergrounding requirements) and force majeure events such as severe storms.[8]

MRPs also typically feature performance metric systems. Some metrics provide the basis for targeted performance incentive mechanisms (PIMs) that aid measurement of performance in areas of special concern to customers and the public. Most commonly, PIMs are used to strengthen incentives for utilities to maintain or improve reliability and customer service quality. A broader range of metrics has recently been considered by regulators in several jurisdictions, including Great Britain and New York.[9]

Demand-side management (DSM) can lower the cost of meeting customer energy needs. MRPs often contain provisions that strengthen utility incentives to facilitate DSM. Utility expenditures on DSM programs are usually tracked.[10] Performance incentive mechanisms can reward utilities for successful DSM programs. Revenue decoupling is often added to sever short-term links between a utility's revenue and electricity sales.[11] This shifts the risk of fluctuations in system use to customers but reduces utility incentives to boost throughput between rate cases. Decoupling also reduces the risks of rate designs that encourage DSM and efficient customer-side distributed generation and storage.

Some MRPs feature earnings sharing mechanisms (ESMs) that share surplus or deficit earnings, or both, between utilities and their customers, which result when the rate of return on equity (ROE) deviates from its public utility commission-approved target.[12] Off-ramp mechanisms may permit review of a plan under prespecified outcomes such as extreme ROEs.

Some MRPs have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. Utilities also may be permitted (or required) to gradually redesign rates for

[6] Lowry and Woolf (2016).
[7] To simplify the discussion, this report will provide illustrations only for revenue cap escalators.
[8] Z factors are discussed further in Appendix A2.
[9] Ofgem (2014) and New York Public Service Commission (2016a).
[10] Institute for Electric Innovation (2014).
[11] Lazar et al. (2016).
[12] Earnings sharing mechanisms are discussed further in Appendix A1.

standard services in fulfillment of commission-approved goals. Marketing flexibility is discussed further in Appendix A.

Plan review and termination provisions are also important in MRPs. Some plans provide for a midterm review of the MRP toward the end of the plan period. These reviews sometimes result in a plan extension without a general rate case. To bolster incentives to achieve lasting efficiency gains, the true-up of a utility's revenue requirement to its cost is sometimes limited if the plan ends with a rate case. For example, the utility may be permitted to keep a share of the difference between its cost and a cost benchmark. Provisions of the latter kind are sometimes called *efficiency carryover mechanisms.*

2.2 MRP Precedents

MRPs have been used in U.S. rate regulation since the 1980s. They were first used on a large scale for railroads and telecommunication carriers.[13] These companies faced significant competitive challenges that complicated regulation. MRPs streamlined regulation and afforded utilities more marketing flexibility and a chance to earn a superior return for superior performance. Some states still use MRPs to regulate services of telecommunication carriers in less competitive markets.[14] The Federal Energy Regulation Commission (FERC) uses MRPs to regulate oil pipelines.[15]

MRPs have been used in several states to regulate retail services of natural gas and electric utilities.[16] In addition to formal rate plans, several states established extended rate freezes for electric utilities during the transition to retail competition. Rate freezes also have been part of the ratemaking treatment for many mergers and acquisitions. Utilities have occasionally and for various other reasons managed to stay out of rate cases for periods exceeding a decade.

Figure 1 shows states that currently use MRPs to regulate retail services of U.S. electric and gas utilities. The figure shows that MRPs are more common for U.S. electric utilities than for gas distributors. Growth in the use of MRPs to regulate electric power distributors has been slowed by grid modernization challenges that complicate plan design. On the other hand, use of MRPs has recently spread to vertically integrated electric utilities in diverse states that include Arizona, Colorado, Georgia, Virginia and Washington. This reflects in part the slowdown and increased predictability of VIEU cost growth in an era when there is less need for large generation plant additions. Many states also have recently experimented with "mini" MRPs involving only two plan years.

Figure 2 shows that MRPs are widely used to regulate retail energy services of Canadian utilities. Overseas, MRPs are the norm in Australia, Ireland, New Zealand and the United Kingdom. Countries that use MRPs in continental Europe include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania and Sweden. MRPs are also common in Latin America.

The impetus for adopting MRPs outside the United States has often come from policymakers rather than utilities. For example, provincial law in Quebec requires the Régie de l'Energie to use an approach to regulation which streamlines regulation, encourages continual performance gains and shares benefits

[13] A discussion of early railroad and telecommunication MRPs can be found in Lowry and Kaufmann (2002).
[14] See, for example, California Public Utilities Commission (2015a), and Vermont Public Service Board (2016).
[15] Federal Energy Regulatory Commission (2015).
[16] MRP precedents for gas and electric utilities have been monitored by the Edison Electric Institute in a series of surveys. The latest is Lowry et al. (2015).

fairly with customers.[17] The Régie recently ordered Hydro-Quebec to operate its power distributor services prospectively under an MRP that the company had opposed.[18]

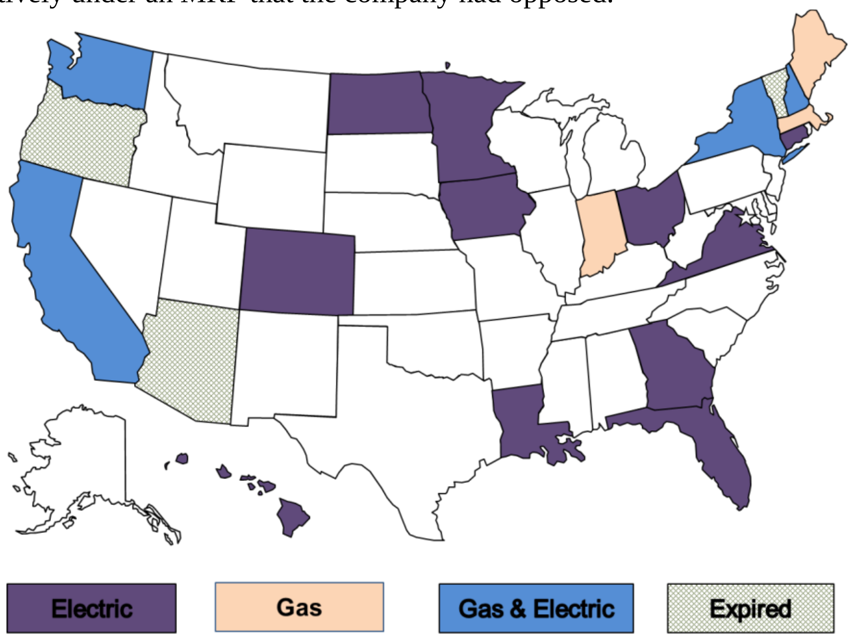

Figure 1. Multiyear Rate Plans in the United States. MRPs are used in many states today to regulate utilities.

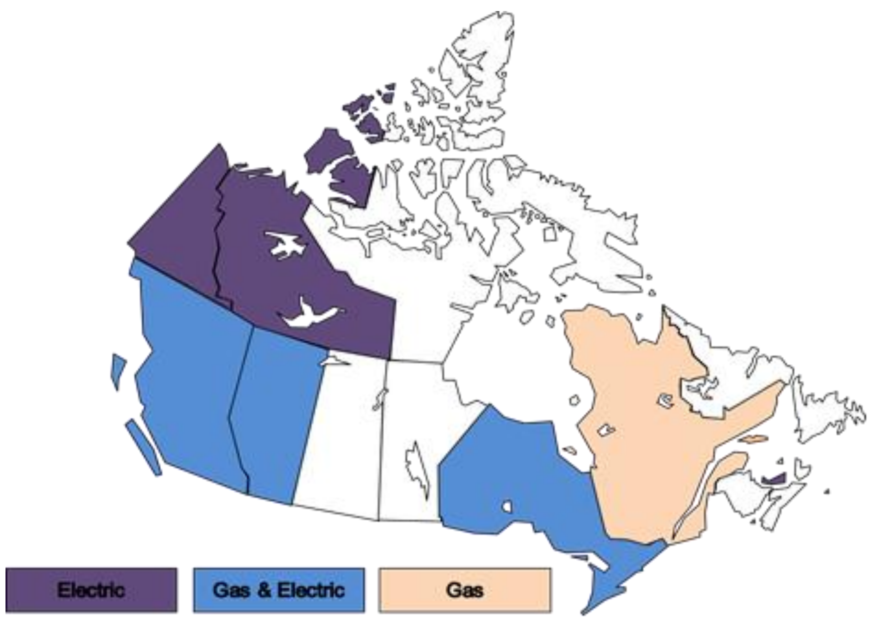

Figure 2. Multiyear Rate Plans in Canada. MRPs have in recent years been used to regulate energy utilities in the most populous Canadian provinces.

[17] Quebec National Assembly (2013, Chapter 16): An Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012, Chapter 1, Division 1 as passed 14 June, 2013.
[18] Régie de l'Energie, D-2017-043, R-3897-2014 Phase 1, April 7, 2017.

3.0 Rationale for Considering MRPs

To explain rationales for considering MRPs we first consider basic features of traditional cost of service regulation (COSR) approaches which are widely used in the United States and then discuss reasons that some jurisdictions have adopted MRPs. We conclude with a discussion of circumstances under which PBR may make sense for some electric utilities under today's business conditions.

3.1 Traditional Cost of Service Regulation

Under COSR,[19] base rates that address costs of capital, labor and materials are reset periodically in rate cases to more effectively recover the utility's cost of service. Rate cases usually occur at irregular intervals and are typically initiated by utilities when the cost of their base rate inputs is growing faster than the corresponding revenue. Between rate cases, growth in base rate revenue depends chiefly on growth in billing determinants such as delivery volumes and numbers of customers served. Most base rate revenue is drawn from usage charges — e.g., charges per kilowatt-hour (kWh) or kilowatts (kW) of system use. The need for rate cases thus depends on a "horse race" between costs and system use.

In the short and medium terms, costs of base rate inputs are driven more by growth in system capacity (e.g., the capacity to serve peak load and to deliver to multiple locations) than by growth in system use. The number of customers served is highly correlated with peak load and an important cost driver in its own right. [20,21] A convenient proxy for the gap between the growth rates of system use and capacity is thus the growth in volume per customer (average use). Earnings are especially sensitive to trends in average use by residential and commercial customers.

Under legacy rate designs, growth in average use bolsters earnings and reduces the need for rate cases, while a decline has the reverse effect. Rate case frequency also depends on input price inflation and the balance between the declining value of older assets due to depreciation and capital expenditures to replace aging infrastructure.

The regulatory cost of COSR is high (for utilities, public utility commissions and stakeholders) when rate cases are frequent or unusually difficult. Rate cases are frequent to the extent that the jurisdiction regulates numerous utilities or the operating conditions facing utilities are continuously unfavorable. Individual rate cases are more difficult to the extent that utilities are large and rate cases involve complex issues.

Regulators understandably take measures to contain regulation's costs. Some of these measures may have adverse consequences. For example, expanded use of cost trackers and a reduced scope for prudence reviews weaken utility incentives to cut costs.[22] Because frequent rate cases and expansive cost trackers are more likely when business conditions are unfavorable, utility performance under traditional regulation tends to deteriorate just when better performance is most needed to keep customer bills reasonable.

[19] Bonbright et al. (1988) is an authoritative treatise on COSR. Lowry and Woolf (2016) provides a more extensive discussion of COSR than provided here, emphasizing incentive problems.
[20] This is because the total number of customers is dominated by the number of residential and small commercial customers, and these customers tend to have more peaked loads.
[21] DSM programs can alter this relationship but to date have had more effect on delivery volumes than they have on the peak demand that drives capacity growth.
[22] Cost trackers have the merit of reducing the need for general rate cases.

Regulatory Lag

Regulatory economists acknowledge the incentive problems with traditional regulation that arise when rate cases are frequent or cost trackers are expansive. In the literature, "regulatory lag" is commonly defined as the time period between the moment when a utility's cost changes and the moment when there is a commensurate change in its rates.[23] James Bonbright, for example, states in a classic treatise that:

> There is the so-called "regulatory lag" — the quite usual delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or rate increase may be put into effect by commission order or otherwise.[24]

The ability of regulatory lag to strengthen a utility's incentive to contain costs has been discussed in the literature. For example, Bonbright states that:

> Quite aside from the recognized undesirability of too frequent rate revisions, commissions recognize the regulatory lag as a practical means of reducing the tendency of a fixed-profit standard to discourage efficient management.[25]

Another noted regulatory economist, Alfred Kahn, suggested that:

> Public utility commissions ought not to even *try* continuously and instantaneously to adjust rate levels in such a way as to hold companies continually to some fixed rate of return; and they probably ought not to try either to hold the rate of return down to the bare cost of capital. The *regulatory lag* — the inevitable delay that regulation imposes in the downward adjustment of rate levels that produce excessive rates of return and in the upward adjustments ordinarily called for if profits are too low — is thus to be regarded not as a deplorable imperfection of regulation but as a positive advantage. Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[26] [emphasis in original]

Under traditional regulation, regulatory lag also delays when rates are changed in response to increasing *external* cost pressures such as input price inflation. For this reason, utility executives and consumer advocates have both emphasized regulatory lag in their rate case evidence despite goals that are often in opposition.

[23] Alternative definitions of "regulatory lag" have been used. One is the period of time between the filing of a request for a rate increase and the increase in rates.

[24] Bonbright et al. (1988).

[25] Ibid., p. 198.

[26] Kahn (1988), p. 48 II.

The Utility Productivity Slowdown of 1973–1986

The productivity growth of a utility is the difference between growth in its operating scale and growth in quantities of inputs that it uses. It is typically measured using an index. Productivity growth reflects changes in diverse business conditions that affect cost, including technological change and realization of scale economies. A multifactor productivity (MFP) index typically considers productivity in use of capital, labor and materials. Appendix B.2 discusses productivity more extensively.

One way to gauge the importance of regulatory lag is to compare utility productivity growth in years when business conditions for utilities were favorable to the growth in years when conditions were unfavorable. Since rate cases tend to be more frequent and cost trackers more expansive when business conditions are unfavorable, productivity growth should be slower. The federal government calculated an index of the MFP of the electric, gas and sanitary sector of the U.S. economy over the 50-year period from 1948 to 1998.[27] We can consider the growth rate of this index during periods of favorable and unfavorable business conditions.

Table 1 presents evidence on two of the most important sources of potential financial attrition for electric and natural gas utilities:

- Trends in the average use of energy by residential and commercial customers
- Price inflation, measured here by the gross domestic product price index (GDPPI)[28]

Average use directly affected MFP growth as measured by the government, but inflation did not.

We constructed summary indicators of potential attrition facing gas and electric utilities. The indicator in each case is the difference between inflation and the average of the growth in average use of energy (gas or electricity) by residential and commercial customers. We report trends over several subperiods between 1927 and 2014.

Results for electric utilities, where data are available for more years, show that these business conditions were quite favorable on balance from the late 1920s until the early 1970s. Except in the 1940s, inflation was generally slow until the late 1960s.[29] Average use of electricity grew rapidly.

These business conditions grew dramatically more adverse for electric utilities in the 1970s and remained so well into the 1980s. Spurred by two oil price shocks, general price inflation was much higher in these years. Inflation in prices of energy commodities such as coal and gas was especially rapid. Combined with slower economic growth, this caused growth in the average use of power by residential and commercial electric customers to slow markedly.

Rate cases were much more frequent.[30] Table 2 reproduces some results of a survey of electric utility rate cases from 1948 through 1977.[31] The table shows that the number of rate cases increased markedly after the mid-1960s and rarely featured a request for rate decreases.

[27] Computation of this index ended in 1998. For a discussion of this research, see Glaser (1993), pp. 34–49.
[28] The GDPPI is the federal government's featured index of inflation in the prices of the economy's final goods and services. It is calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce.
[29] Rapid inflation during the Korean War was offset by slower inflation in later years of the 1950s.
[30] See Joskow and MacAvoy (1975).
[31] Braeutigam and Quirk (1984), p. 47.

Table 1. Indicators of Energy Utility Financial Attrition in the United States (1927–2014)

	Average Annual Electricity Use					Average Annual Natural Gas Use					GDPPI Inflation[4]		Summary Attrition Indicators	
	Residential[1]		Commercial[1]		Average	Residential[2]		Commercial[3]		Average				
	Level	Growth Rate	Level	Growth Rate	Growth Rate	Level	Growth Rate	Level	Growth Rate	Growth Rate	Level	Growth Rate	Electric	Natural Gas
Multiyear Averages					[A]					[B]		[C]	[C]-[A]	[C]-[B]
1927-1930	478	7.06%	3,659	6.67%	6.86%	NA	NA	NA	NA	NA	9.71	-3.92% [5]	-10.79%	NA
1931-1940	723	5.45%	4,048	2.00%	3.73%	NA	NA	NA	NA	NA	7.99	-1.59%	-5.31%	NA
1941-1950	1,304	6.48%	6,485	5.08%	5.78%	NA	NA	NA	NA	NA	11.37	5.26%	-0.52%	NA
1951-1960	2,836	7.53%	12,062	6.29%	6.91%	NA	NA	NA	NA	NA	16.04	2.42%	-4.49%	NA
1961-1972	5,603	5.79%	31,230	8.79%	7.29%	125	1.78% [6]	726	3.97% [6]	2.88% [6]	20.35	2.98%	-4.32%	0.10% [7]
1973-1980[8]	8,394	2.03%	50,576	2.53%	2.28%	117	-2.22%	764	-0.63%	-1.42%	34.74	7.18%	4.90%	8.61%
1981-1986[8]	8,820	0.12%	54,144	0.81%	0.46%	98	-2.67%	651	-3.84%	-3.26%	54.22	4.57%	4.11%	7.82%
1987-1990	9,424	1.39%	60,211	2.29%	1.84%	93	-1.25%	631	1.33%	0.04%	63.32	3.33%	1.49%	3.29%
1991-2000	10,061	1.15%	67,006	1.68%	1.41%	88	-0.37%	639	0.30%	-0.04%	75.70	2.03%	0.62%	2.07%
2001-2007	10,941	0.73%	74,224	0.64%	0.68%	77	-2.12%	594	-1.55%	-1.83%	89.83	2.47%	1.79%	4.30%
2008-2014	11,059	-0.38%	75,311	-0.22%	-0.30%	72	0.58%	597	1.75%	1.17%	103.53	1.60%	1.90%	0.43%

[1] U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

[2] Energy Information Administration, Historical Natural Gas Annual 1930 Through 1999 (Table 38. Average Consumption and Annual Cost of Natural Gas per Consumer by State, 1967-1989) (1967-1986); Energy Information Administration series N3010US2, "U.S. Natural Gas Residential Consumption (MMcf)" and Energy Information Administration series NA1501_NUS_8, "U.S. Natural Gas Number of Residential Consumers (Count)" (1987-2014).

[3] Includes vehicle fuel. Sources: Energy Information Administration series NA1531_NUS_10, "U.S. Natural Gas Average Annual Consumption per Commercial Consumer (Mcf)" (1967-1986); Energy Information Administration series N3020US2, "Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in the U.S. (MMcf)" (1987-2014), Energy Information Administration series N3025US2, "U.S. Natural Gas Vehicle Fuel Consumption (MMcf)" (1997-2014), Energy Information Administration series NA1531_NUS_8, "U.S. Natural Gas Number of Commercial Consumers (Count)" (1987-2014).

[4] Bureau of Economic Analysis, Table 1.4.4. Price Indexes for Gross Domestic Product, Gross Domestic Purchases, and Final Sales to Domestic Purchasers, Revised October 28, 2016.

[5] Growth rate is for 1930 only. Levels are for 1929 and 1930. Data are not available before 1929.

[6] Levels are for 1967-1972 and growth rates are for 1968-1972. Data are not available before 1967.

[7] Note that the growth rates used to compute this value cover different periods.

[8] Shaded years had unusually unfavorable business conditions.

Table 2. U.S. Electric Utility Rate Cases: 1948–1977[32]

Period	Number of Rate Cases	Company Initiated Rate Cases			PUC Initiated Rate Cases
		Number	Rate Increases	Rate Decreases	
1948-1952	46	45	42	3	1
1953-1957	34	31	28	3	3
1958-1962	43	39	38	1	4
1963-1967	17	16	12	4	1
1968-1972	104	100	96	4	4
1973-1977	119	119	119	0	0

After 1986, inflation slowed to a pace more typical of the 1950s and 1960s. However, sluggish growth in average use continued. Thus, business conditions improved on balance, but were less favorable than those in the decades preceding the first oil price shock.[33]

Table 3 and Figure 3 show the trend in the federal government's index of the MFP of the electric, gas and sanitary sector of the U.S. economy over the 50 years from 1948 to 1998. The MFP growth of the sector was remarkably brisk until the early 1970s, averaging 3.9 percent annually compared to the 2.1 percent trend in the MFP of the entire private business sector of the economy.

[32] Most rate cases are initiated by utilities. However, state regulatory commissions may initiate general rate cases to investigate potential excessive utility earnings.

[33] Average use data for a comparably long period were not found for natural gas distributors. However, average use of natural gas fell briskly during the 1973 to 1986 period, whereas it had risen briskly from 1968 to 1972. Inflation and average use trends were thus extremely unfavorable for gas distributors from 1973 to 1986. While inflation slowed after 1986, declining average use continued so that, on balance, business conditions improved for gas distributors but were less favorable than in the 1960s.

Table 3. Multifactor Productivity Growth of Electric, Gas, and Sanitary Utilities and the U.S. Private Business Sector: 1949–1998

	Electric, Gas, and Sanitary Utilities[1]		U.S. Private Business Sector[2]		MFP Growth Differential
	Level	Growth Rate	Level	Growth Rate	
Year		[A]		[B]	[A - B]
1948	34.67		50.34		
1949	35.23	1.60%	50.93	1.16%	0.45%
1950	37.85	7.16%	54.63	7.03%	0.14%
1951	41.50	9.19%	55.90	2.29%	6.90%
1952	43.27	4.19%	56.39	0.87%	3.32%
1953	44.95	3.81%	57.66	2.22%	1.59%
1954	46.73	3.87%	57.76	0.17%	3.71%
1955	50.37	7.51%	60.49	4.62%	2.89%
1956	52.90	4.89%	60.20	-0.49%	5.37%
1957	54.86	3.64%	61.07	1.45%	2.19%
1958	56.36	2.69%	61.37	0.48%	2.21%
1959	59.91	6.11%	63.51	3.44%	2.67%
1960	61.68	2.92%	63.90	0.61%	2.31%
1961	63.18	2.40%	65.27	2.11%	0.28%
1962	66.26	4.77%	67.61	3.52%	1.24%
1963	67.57	1.96%	69.66	2.99%	-1.03%
1964	71.12	5.12%	72.39	3.85%	1.28%
1965	74.02	3.99%	74.73	3.18%	0.81%
1966	77.01	3.96%	76.98	2.96%	1.00%
1967	79.44	3.11%	77.07	0.13%	2.98%
1968	82.99	4.37%	79.12	2.62%	1.75%
1969	85.23	2.67%	78.63	-0.62%	3.29%
1970	86.64	1.63%	78.54	-0.12%	1.76%
1971	87.66	1.18%	80.98	3.06%	-1.88%
1972	89.16	1.69%	83.41	2.97%	-1.28%
1973	90.84	1.87%	85.66	2.65%	-0.79%
1974	87.85	-3.35%	82.54	-3.71%	0.37%
1975	88.04	0.21%	83.32	0.94%	-0.73%
1976	89.16	1.27%	86.44	3.68%	-2.41%
1977	88.97	-0.21%	87.80	1.57%	-1.78%
1978	88.88	-0.11%	88.98	1.32%	-1.43%
1979	87.85	-1.16%	88.59	-0.44%	-0.72%
1980	87.38	-0.53%	86.63	-2.23%	1.69%
1981	87.38	0.00%	86.73	0.11%	-0.11%
1982	86.54	-0.97%	84.10	-3.08%	2.12%
1983	85.42	-1.30%	86.44	2.75%	-4.05%
1984	88.32	3.34%	89.27	3.22%	0.11%
1985	88.22	-0.11%	90.15	0.98%	-1.08%
1986	88.50	0.32%	91.61	1.61%	-1.29%
1987	88.60	0.11%	91.90	0.32%	-0.21%
1988	92.06	3.83%	92.49	0.63%	3.19%
1989	92.43	0.41%	92.98	0.53%	-0.12%
1990	93.83	1.51%	93.17	0.21%	1.30%
1991	93.64	-0.20%	92.20	-1.05%	0.85%
1992	93.46	-0.20%	94.34	2.30%	-2.50%
1993	95.89	2.57%	94.73	0.41%	2.15%
1994	96.45	0.58%	95.80	1.13%	-0.54%
1995	98.69	2.30%	96.00	0.20%	2.10%
1996	99.91	1.22%	97.56	1.61%	-0.39%
1997	99.91	0.00%	98.73	1.19%	-1.19%
1998	100.00	0.09%	100.00	1.28%	-1.18%
Annual Averages					
1949-1972		3.94%		2.10%	1.83%
1973-1986		-0.05%		0.67%	-0.72%
1987-1998		1.02%		0.73%	0.29%

[1] Bureau of Labor Statistics, Multifactor Productivity, Electric, Gas and Sanitary Utilities (SIC 49).

[2] Bureau of Labor Statistics, Multifactor Productivity, Private Business Sector.

Note: Shaded years had unusually unfavorable business conditions.

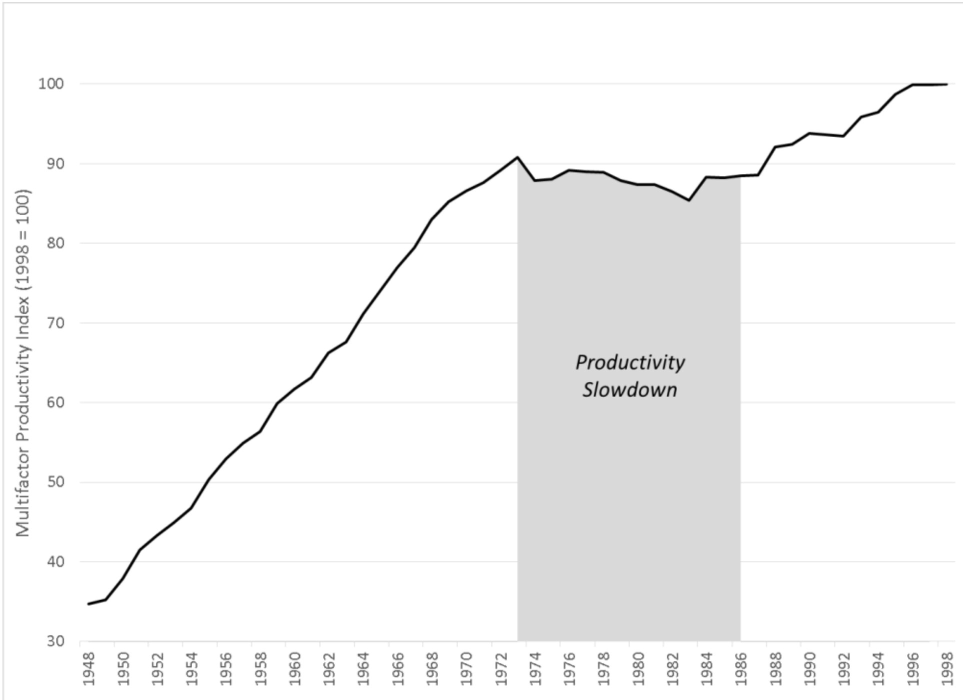

Figure 3. Multifactor Productivity Trend of U.S. Electric, Gas and Sanitary Utilities (1948–1998). MFP growth of U.S. utilities slowed during the period 1973 to 1986 under unfavorable business conditions.

The MFP growth of electric, gas and sanitary utilities fell to zero on average during the following years of markedly unfavorable business conditions, when rate cases were much more frequent. Both capital and labor productivity growth of this utility sector slowed markedly. MFP

growth of the U.S. private business sector exceeded that of electric, gas and sanitary utilities by around 72 basis points annually on average during these years.[34]

The generation sector of the utility industry was a notable problem area during this period. Overbuilding generation capacity and cost overruns and delays on generation plant additions were widespread. Resultant overcapacity boosted sales in wholesale markets and widened the gap between wholesale and retail power prices. This gap was one of the factors that ultimately led to restructuring of retail power markets in many states.

MFP growth of utilities resumed at a slower 1.02 percent average annual pace from 1987 to 1998, a period during which the frequency of rate cases slowed. Utility MFP trends exceeded private business sector MFP trends by a modest 29 basis points on average.

The MRP Alternative

<u>Advantages</u>

A core advantage of MRPs is their potential to strengthen cost containment incentives.[35] The attrition relief mechanism can provide timely, predictable rate escalation that permits an extension of the period

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[34] A basis point is one-hundredth of 1 percent.
[35] For further discussions of the rationale for MRPs see Lowry and Kaufmann (2002), Lowry and Woolf (2016), Comnes et al. (1995), and Kaufmann and Lowry (1995).

between rate cases. Escalation is based on cost forecasts, industry cost trends or both, rather than the utility's *specific* costs. Regulatory lag is thus achieved without sacrificing the timeliness of rate relief, increasing opportunities for a utility to bolster earnings from efforts to contain costs addressed by the ARM (i.e., costs that are not tracked). A well-designed efficiency carryover mechanism can magnify the incentive "power" of the MRP.[36] Loosening the link between a utility's cost and its revenue gives it an operating environment more like that which producers in competitive markets experience.

MRPs can also encourage more operating flexibility in areas where the need for flexibility is recognized. Reduced rate case frequency means that the prudence of management strategies must be considered less frequently. Utilities are more at risk from bad outcomes (e.g., needlessly high capex) and can gain more from good outcomes (e.g., low capex). This potential advantage of MRPs in facilitating operating flexibility has been most thoroughly developed in the area of marketing flexibility (see Appendix A for further discussion).

PIMs play a special role in multiyear rate plans. The plans can strengthen incentives to contain costs.[37] These include costs incurred to maintain or improve service quality and worker safety. In competitive markets, a producer's revenue can fall abruptly if the quality of its offerings falls. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality and safety.[38]

Advantages of MRPs in encouraging utilities to consider cost-effective DSM and other distributed energy resources (DERs) are not widely recognized. MRPs can strengthen incentives to use DERs to contain load-related costs that are reflected in retail rates. The combination of an MRP, revenue decoupling, PIMs to encourage efficient DSM, and the tracking of DER-related costs can provide four "legs" for the DER "stool."[39] MRPs can reduce the need for complicated measurement of load and cost savings from DERs.

With stronger performance incentives and greater operating flexibility, MRPs can encourage better utility performance. Benefits of better performance can be shared with customers via earnings sharing mechanisms, plan termination provisions and careful ARM design. Customers can also benefit from more market-responsive rates and services. The strengthened performance incentives and reduced preoccupation with rate cases which MRPs provide can create a more performance-oriented corporate culture at utilities. This may increase the likelihood of success in mergers, acquisitions and unregulated market ventures in which utility companies engage.

MRPs also can increase the efficiency of regulation. Rate cases can be less frequent and better planned and executed. MRPs also facilitate scheduling rate cases so that proceedings overlap less. Streamlining ratemaking processes can reduce cost burdens on ratepayers and free up resources in the regulatory community to more effectively address other important issues, such as rules of prospective application. Senior utility managers have more time to attend to their basic business of providing quality service cost-effectively. Streamlined regulation has special appeal in situations where costs of regulation are especially high due to numerous utilities, large utilities or especially difficult regulatory issues. It is not surprising, then, that several commissions with unusually large regulatory burdens (e.g., Ontario and Germany) have been MRP leaders.

[36] See Sections 4 and 5 and Appendix A1 for further discussion of efficiency carryover mechanisms.
[37] See, for example, Comnes et al. (1995).
[38] Alberta Utilities Commission (2012), p. 186.
[39] A three-legged stool for DSM consisting of revenue decoupling, performance incentive mechanisms, and DSM cost trackers is discussed in York and Kushler (2011).

Disadvantages

MRPs are complex regulatory systems. The transition to these plans can be challenging in some jurisdictions. As we discuss at some length in Section 4, it can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers. Controversies can arise in plan design, as they do in COSR. Poorly designed plans can create opportunities for strategic behavior that reduces plan benefits for customers. For these and other reasons, most American jurisdictions have not yet adopted MRPs for gas and electric utilities. The concluding section of this report provides a more extensive discussion of reasons for the continued popularity of COSR.

3.2 How MRPs Can Help Address Contemporary Challenges

Benefits of MRPs tend to be greatest where traditional regulation is especially disadvantageous. These include situations where rate cases are especially frequent, a large number of utilities are regulated, marketing flexibility is especially desirable, and regulators have numerous other issues to attend to. We discuss here the extent to which these conditions are present today.

Need for Rate Cases and Expansive Cost Trackers

Table 1 shows that key business conditions that cause utility attrition are considerably less favorable today on balance than they were in the decades before 1973. Since the start of the Great Recession, sluggish economic growth and energy efficiency gains have caused unusually slow growth in average use of electricity by residential and commercial customers.[40] The financial stress on utilities of this development has been partly offset to date by unusually slow input price inflation.[41] However, inflation may be higher in the future due, for example, to rising bond yields. Increased penetration of DERs could further slow growth in average use.

The need for frequent rate cases varies among electric utilities. Variation in capex requirements is a major reason. In a period of sustained high capex, utilities need brisk escalation in rates, especially when the capex does not automatically produce new revenue. Some utilities need high capex today to replace aging distribution assets. This kind of capex does not, like distribution system extensions, typically produce new revenue without a rate case or cost tracker. Technological change has created opportunities for "smart grid" capex that improves utility performance but may not trigger much new revenue.[42]

Distribution capex induces less growth in the total cost of a VIEU than it does in the cost of a UDC. Furthermore, slow demand growth and interest by some state regulatory commissions for VIEUs to rely on power purchase agreements rather than build and own more power plants is reducing the need for new VIEU generation capacity. On the other hand, some VIEUs are refurbishing or replacing old power plants.

[40] Demand growth in some states has also been affected by distributed generation and deindustrialization.
[41] Reduction in utility revenue due to declines in average electricity use can, in any event, be addressed by targeted remedies such as revenue decoupling.
[42] Some of these expenditures do, however, produce offsetting operation and maintenance cost savings.

Technological Change

Technological change is creating new ways to meet the energy needs of customers. Well-designed MRPs can, by strengthening performance incentives and increasing operating flexibility, drive utilities to embrace these technologies where they are cost effective. However, when new technologies involve sizable up-front capex with little automatic revenue growth they can complicate MRP design.

Number of Utilities

The number of utilities that a state public utility commission regulates rarely grows, but sometimes falls due to mergers and acquisitions. Several states (e.g., California, New York, Pennsylvania and Texas) still regulate five or more electric utilities, and states must typically also regulate natural gas, telecommunications and water utilities.[43] Mergers and acquisitions have caused the number of utilities owned by some companies to rise over the years. Multi-utility companies have more incentive to adopt MRPs and other economical approaches to regulation.[44]

Marketing Flexibility

Marketing flexibility is increasingly useful to utilities in order to fashion time-sensitive rates, green power services, and miscellaneous new services enabled by new technologies. VIEUs may have greater need for marketing flexibility than UDCs. One reason is that the large-load customers whose demand has traditionally been most sensitive to the terms of service make a much larger contribution to a VIEU's base rate revenue. Another reason is that VIEUs may benefit more from renewable energy and electric vehicle options than UDCs since VIEUs may provide the power from company-owned generation. In addition, time-sensitive pricing can contain generation costs as well as transmission and distribution capacity needs.

Instability Concerns

We noted above that traditional regulation provides weaker incentives for cost management when business conditions are especially adverse. This idiosyncrasy of traditional regulation raises questions about its ability to cope with increased penetration of customer-side distributed generation and storage. Penetration slows growth in average electricity use. To the extent that this leads to more frequent rate cases and more expansive cost trackers, utility performance deteriorates. Utilities may, for example, choose such a time for high replacement capex. The end result can be higher rates that further discourage use of grid services.[45] This is a source of potential instability in the utility industry. The contrast to competitive markets is striking. In a period of weak demand, prices fall in competitive markets and firms scramble to cut their costs.

[43] In contrast, regulation outside the United States is often conducted at the national level.

[44] Minneapolis-based Xcel Energy is an example of a multi-utility company that has publicly embraced MRPs. See Xcel Energy's "Strategic Plan for Growth," May 2015, http://investors.xcelenergy.com/Cache/1500071832.PDF?O=PDF&T=&Y=&D=&FID=1500071832&iid=4025308, and Xcel Energy's SEC Schedule 14A filed April 2015, http://investors.xcelenergy.com/Cache/28758163.PDF?O=PDF&T=&Y=&D=&FID=28758163&iid=4025308.

[45] For further discussion of the potential for a utility "death spiral," see Graffy and Kihm (2014).

Competing Needs for Regulatory Resources

Regulatory resources that are currently devoted to rate cases have many alternative uses in this era of rapid change. Among the areas where thoughtful review is currently needed are rate design, distribution system planning, and the terms of compensation for customer-side DER services.

Difficulty of MRP Implementation

The difficulty of implementing MRPs changes over time and varies considerably among utilities. One key challenge is the identification of a reasonable ARM. Implementation of index-based ARMs has traditionally been easier for UDCs than for vertically integrated utilities. The cost of UDC base rate inputs tends to grow gradually and predictably as the economies UDCs serve gradually expand. In contrast, VIEUs have in the past had "stair step" cost trajectories with large rate increases when large power plants came into service alternating with periods of slow cost growth as new units depreciated. Another complication for VIEUs was that the exact timing of major plant additions was often uncertain, due in part to construction delays.

However, many UDCs have in recent years proposed accelerated grid modernization programs involving several years of high capex. The need for these programs is often difficult for regulators to judge in an era of rapid technological change and shifting demand. VIEUs, meanwhile, are experiencing *more gradual* cost growth because fewer generation capacity additions are needed and capacity that is built tends to be more modular natural gas-fired or wind-powered units. Depreciation of older generation plant meanwhile slows rate base growth.[46] Figures 4 and 5 illustrate the changing needs for rate escalation for UDCs and VIEUs.

Consider also that jurisdictions vary in their regulatory traditions and human capital (the experience and the expertise of regulatory practitioners). Generally speaking, adoption of MRPs is easier for jurisdictions that have experience with the use of forward test years in rate cases. Accumulation of experience with MRPs in the United States and improvements in MRP design will facilitate broader implementation.

Conclusions

Our analysis suggests that unusually slow inflation since the Great Recession of 2008 has thus far offset declining residential and commercial average use to contain the need for electric utilities to file frequent rate cases. However, these business conditions are still less favorable on balance than they were before 1972 when COSR worked well and became a tradition. Resumption of normal inflation and accelerated penetration of customer-side DERs may well occur and would spark more interest in MRPs. MRPs can also address the need for marketing flexibility.

Whereas the need for multiyear rate plans may be greater for UDCs with high capex, the ease of implementing these plans is often greater for VIEUs today. VIEUs also may have stronger interest in marketing flexibility. This helps to explain why use of MRPs is growing most rapidly in the United States for VIEUs.

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[46] However, some utilities are building new, cleaner generating facilities (including emissions control equipment) or modernizing older generation plants. Aging generating capacity (especially nuclear capacity) can have rising operating costs.

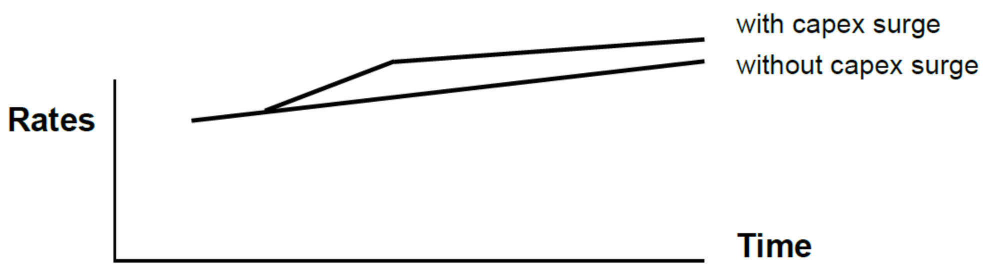

Figure 4. Rate Escalation Requirements for UDCs. Capex surges can accelerate the normally gradual escalation of UDC rates.

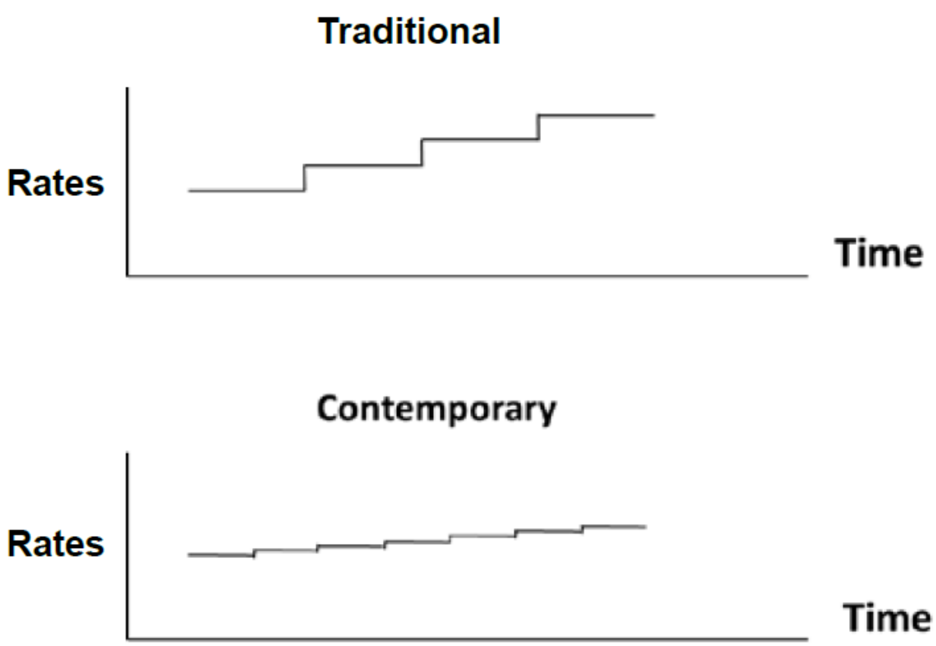

Figure 5. Rate Escalation Requirements for VIEUs. Rate escalation requirements of VIEUs are becoming more gradual.

Growing familiarity with best practices in the design of plans for UDCs may encourage greater use in this utility sector. Use of MRPs for UDCs may also increase as they complete accelerated grid modernization programs that complicate plan design and return to gradual cost growth. Companies and commissions with unusually large regulatory burdens gain special advantages from streamlined regulation. Some of these companies and commissions are likely to be MRP leaders.

4.0 MRP Design Issues

This section takes a deeper look at important issues in MRP design. We first consider how attrition relief mechanisms (ARMs) can cap rate and revenue growth and then discuss major approaches to ARM design. Following are discussions of cost trackers, decoupling, performance metric systems and efficiency carryover mechanisms.

4.1 Attrition Relief Mechanisms

Rate Caps vs. Revenue Caps

ARMs can escalate allowed rates or revenue. Limits on rate growth are sometimes called *price caps.*[47] In price cap plans, allowed rate escalation is often applied separately to multiple service "baskets." For example, there might be separate baskets for small-load (e.g., residential and general service) and large-load customers. The utility can typically raise rates for services in each basket by a common percentage that is determined by the ARM, cost trackers and any earnings sharing adjustments.[48] Customers in each basket are insulated from the discounts and demand shifts going on with services in other baskets, except as these developments influence shared earnings or cost trackers.

Price caps have been widely used to regulate utilities, such as telecommunications carriers, which are encouraged to promote use of their systems. In the electric utility industry, legacy rate designs feature usage charges that are well above the utility's short-run marginal cost of service provision.[49] With less frequent rate cases, price caps can therefore make utility earnings more sensitive to the kWh and kW of system use, strengthening utility incentives to encourage greater use.

Under revenue caps, the focus is on limiting growth in allowed revenue (the revenue requirement).[50] Services may still be grouped in baskets. Revenue caps are often paired with a revenue decoupling mechanism that relaxes the link between revenue and system use.

Methods for ARM Escalation

Several well-established approaches to ARM design can, with sensible modifications, be used to escalate rate or revenue caps. We use revenue cap examples in the following discussion.

<u>Indexing</u>

An indexed ARM is developed using index and other statistical research on utility cost trends. For example, a revenue cap index for a power distributor might take the following form:

$$growth\ Revenue = Inflation - X + growth\ Customers + Y + Z \qquad [2]$$

The inflation measure in such a formula is often a macroeconomic price index such as the Gross Domestic Product Price Index. However, custom indexes of utility input price inflation are sometimes

[47] A notable early discussion of price caps for electric utilities is Lowry and Kaufmann (1994).
[48] In some plans, slower growth in rates for some services in a basket can, within limits, permit more rapid rate growth for other services in the same basket.
[49] Marginal cost is the additional cost incurred to provide a small increment of service.
[50] The allowed revenue yielded by a revenue cap escalator must be converted into rates, requiring assumptions for billing determinants.

used in ARM design. X, the productivity or "X" factor, usually reflects the average historical trend in the multifactor productivity of a group of peer distributors. A stretch factor (sometimes called *consumer dividend*) is often added to X to guarantee customers a share of the benefit of the stronger performance incentives that are expected under the plan.

Index-based ARMs compensate utilities automatically for important external cost drivers such as inflation and customer growth. This provides timely rate relief that reduces attrition and operating risk without weakening performance incentives. Between rate cases, customers can be guaranteed benefits of productivity growth which equals (or, with a stretch factor exceeds) industry norms. Controversies over cost forecasts can be avoided.

On the other hand, index-based ARMs are typically based on long-run cost trends. They may therefore undercompensate utilities when capex is surging and overcompensate them on other occasions, such as the years following a surge. Capex surges can be addressed by cost trackers, but trackers involve their own complications, as we discuss further below. Design of indexed ARMs applicable to capital cost sometimes involve statistical cost research that is complex and sometimes controversial.[51] Consultants will seek entry to the field by advocating unusual values for X which serve the interests of their clients. However, base productivity trends chosen by North American regulators for X factor calibration have tended to lie in a fairly narrow range to date (e.g., zero to 1 percent).

Forecasts

A forecasted ARM is based on multiyear cost forecasts. An ARM based solely on forecasts increases revenue by predetermined percentages in each plan year (e.g., 4 percent in 2018, 5 percent in 2019 and 3 percent in 2020). The outcome is much like that of a rate case with multiple forward test years.

Familiar accounting methods can be used to forecast growth in capital cost. The trend in the cost of older capital is relatively straightforward to forecast since it depends chiefly on mechanistic depreciation.[52] The more controversial issue is the value of plant additions during the plan.

Shortcuts are sometimes taken in preparing forecasts for ARM design. For example, forecasted plant additions may be set for each plan year at the utility's average value in recent years [53] or at its value for the test year of the most recent rate case. Operation and maintenance (O&M) expenses are sometimes forecasted using index-based formulas similar to equation [2].

One important advantage of forecasted ARMs is their ability to be tailored to unusual cost trajectories. For example, a forecasted ARM can provide timely funding for an expected capex surge. Some forecasted ARMs make no adjustment to rates during the plan if the actual cost incurred differs from the forecast. This approach to ARM design can generate fairly strong cost containment incentives despite the use of company-specific forecasts.

On the downside, forecasted ARMs do not protect utilities from unforeseen changes in inflation and operating scale.[54] The biggest problem with forecasted ARMs, however, is that it can be difficult to establish just and reasonable multiyear cost forecasts. It is often difficult to ascertain the value to

[51] For example, productivity studies filed in proceedings to establish an MRP often use mathematically stylized representations of capital costs which differ from those used in traditional ratemaking. Witnesses have disagreed on the appropriate capital cost treatment and sample period for a productivity study.
[52] Note, however, that salvage value and decommissioning costs are sometimes controversial.
[53] The practice of basing a utility's plant addition budgets on its historical plant additions may weaken its capex containment incentives if used repeatedly.
[54] Operating scale risk can be reduced by forecasting unit costs (e.g., cost per customer) and then truing up for actual scale growth.

customers in a given cost forecast. Resources that the regulatory community may expend on benchmarking and engineering studies to develop competent independent views of needed utility cost growth can be sizable.

Hybrids

"Hybrid" approaches to ARM design use a mix of indexing and other escalation methodologies.[55] The most popular hybrid approach in the United States involves separate treatment of revenues (or rates) that compensate utilities for their O&M expenses and capital costs. Indexes address O&M expenses while forecasts address capital costs.

Indexation of O&M revenue provides protection from hyperinflationary episodes and limits the scope of forecasting evidence. Good data on O&M input price trends of electric (and gas) utilities are available in the United States. The forecast approach to capital costs, meanwhile, accommodates diverse capital cost trajectories. The complicated issue of designing index-based ARMs for capital revenue is sidestepped. On the other hand, capex forecasts are required and can be controversial.

Rate Freezes

Some MRPs feature a rate freeze in which the ARM provides no rate escalation during the plan. Revenue growth then depends entirely on growth in billing determinants and tracked costs. Freezes usually apply only to base rates but have occasionally applied to rates for energy procurement. An analogous concept for a plan with revenue decoupling is the revenue/
customer freeze, which permits revenue to grow at the (typically gradual) pace of customer growth.

4.2 Cost Trackers

Basic Idea

A cost tracker is a mechanism for expedited recovery of specific utility costs. Balancing accounts are typically used to track unrecovered costs that regulators deem prudent. Costs are then recovered by tariff sheet provisions called *riders.*

A cost tracker helps a utility's revenue track its own costs more closely. While this is contrary to the spirit of PBR — which focuses on strengthening incentives — it can make it easier for a utility to operate under an MRP, which has an ARM for other costs of base rate inputs. Where cost containment incentives generated by trackers are a concern, methods are available to address them. For example, tracked costs can be subject to especially intensive prudence review.[56] Tracker mechanisms can be incentivized, as we discuss further below.

Capital Cost Trackers

Capital cost trackers compensate utilities for annual costs (e.g., depreciation, return on asset value, and taxes) that capex (or plant additions) give rise to. Such trackers are sometimes used in MRPs to address capex surges that are difficult to address with an ARM. Capex surges are sometimes needed — for

[55] A "hybrid" designation can in principle be applied to a number of ARM design methods, including the design used in Great Britain. However, it would not apply to regulatory systems, such as those used in Vermont, which index O&M revenue but use cost of service regulation for capital cost.
[56] The reduction in rate cases that MRPs make possible frees up resources to review these costs.

example, when VIEUs make large additions to generating capacity, replace large components of existing generating plants, or add extensive emission control systems. VIEUs and UDCs alike may need high capex for rapid build-out of AMI or other smart grid technologies, to meet increased safety and reliability standards, and to replace facilities built in earlier periods of rapid system growth.

Forecasted and hybrid ARMs can address expected capex surges better than index-based ARMs. Thus, capital cost trackers are more commonly combined with index-based ARMs. However, MRPs with forecasted or hybrid ARMs sometimes permit utilities to request supplemental revenue for unforeseen capex, or for capex with uncertain completion dates.[57]

Ratemaking Treatments of Tracked Costs

Supplemental revenue that capital cost trackers produce is often based on capex forecasts. Treatment of variances from approved budgets then becomes an issue. Some capital cost trackers return all capex underspends to ratepayers promptly. As for overspends, some trackers permit conventional prudence review treatment. In other cases, no adjustments are subsequently made between rate cases if capex exceeds budgets. Mechanisms also have been approved in which deviations from budgeted amounts that are in prescribed ranges are shared formulaically (e.g., 50-50) between the utility and its customers.

Appraising the Need for Trackers

A key question in approvals of capital cost trackers is the need for tracking. This question involves two issues: the need for high capex and the need for tracking the capex. It can be challenging to ascertain the need for high capex. For example, trackers for energy distributors sometimes address costs of accelerated system modernization. The need for a particular plan of modernization can be more challenging to appraise than the need for other kinds of capex surges, such as those for new generation capacity or emissions control facilities.[58] Accelerated distribution modernization plans involve many decisions about emerging technology and consumer expectations, as well as timing and scale issues, and regulators in some jurisdictions may not have much expertise in evaluating them.

Determining the need for a capital cost tracker is complicated for a utility operating under an ARM that provides some compensation for capex. An indexed ARM, for example, escalates revenue associated with an older plant between rate cases even though the cost of that plant tends to decline due to depreciation. Furthermore, the X factor in the escalator reflects productivity growth by peer group utilities which has been slowed by capex.[59] If the utility is given dollar-for-dollar compensation for substandard productivity growth when normal kinds of capex surge, but the X factor in the revenue cap formula reflects only the industry productivity trend when capex does not surge, customers are not ensured the benefit of the industry productivity trend in the long run, even if it is achievable.

Ratemaking Treatment of Other Costs

Another issue that arises when considering a capital cost tracker is the ratemaking treatment of costs not included in the tracker. Separate recovery of certain capex costs means that the cost of residual capital —

[57] For example, trackers have been used in conjunction with hybrid or forecasted ARMs to address costs of new generating facilities, major generator refurbishments and AMI.

[58] Generation plant additions also require discretion, but regulators of VIEUs have years of experience considering both the need for new capacity and the types of generation technology. Many states require integrated resource planning or a certificate of public convenience and necessity, or both, before additions to generation capacity can proceed. In addition, there are often competitive alternatives to a utility's proposal to increase capacity. Proponents of these alternatives press their cases in these hearings.

[59] Capex often slows growth in multifactor productivity, even while accelerating O&M productivity.

consisting mainly of gradually depreciating older plant — tends to rise more slowly and predictably. If *all* capex cost flows through trackers, the residual capital cost is that of older plants and may *decline* due to depreciation. Additionally, productivity growth of electric O&M inputs may be brisk. For these reasons, expansive capex trackers often coincide with freezes on rates addressing costs of other inputs.[60] This "tracker/freeze" approach to MRP design has recently been used by VIEUs in Arizona, Colorado, Florida, Louisiana and Virginia.[61]

Capital Cost Tracker Precedents

There are numerous precedents for capital cost trackers in the regulation of retail rates for U.S. gas, electric and water utilities.[62] The popularity of such trackers reflects in part the generally traditional approach to regulation in U.S. jurisdictions. Most capital cost trackers in the United States are not embedded in MRPs with ARMs that provide automatic rate escalation for cost pressures. The alternative to these trackers for regulators is thus more frequent rate cases that require review of costs of *all* base rate inputs and weaken utilities' incentives to contain them. Note also that many trackers are approved in jurisdictions that do not have fully forecasted test years.

Capital cost trackers have been components of a number of MRPs. Plans in California and Maine, for example, have had trackers for costs of AMI.[63] Plans in Alberta and Ontario have permitted cost trackers for a broader range of distributor capex.[64]

Capital cost trackers are occasionally incentivized. In California, for example, the AMI cost trackers of Southern California Edison and San Diego Gas & Electric have involved preapproved multiyear cost forecasts. Each company has been permitted to recover 100 percent of its forecasted cost up to a cap without further prudence review. Above the cap, each company can recover 90 percent of incremental overspends in a certain range without a prudence review. Beyond this range, recovery of incremental overspends requires a prudence review. San Diego Gas & Electric was permitted to keep 10 percent of its underspends.

[60] In an MRP with a revenue cap, the analogous ratemaking treatment is a revenue per customer freeze.
[61] See, for example, Arizona Corporation Commission (2012), Colorado Public Utilities Commission (2015), Florida Public Service Commission (2013), Louisiana Public Service Commission (2014), and Virginia Acts of Assembly (2015).
[62] Lowry et al. (2015).
[63] California Public Utilities Commission (2007a), California Public Utilities Commission (2008b), and Maine Public Utilities Commission (2008).
[64] See Alberta Utilities Commission (2012), for a discussion of capital cost trackers in Alberta distribution regulation and Section 6.7 of this report for a discussion of capital cost trackers in Ontario power distribution regulation.

Decoupling Under an MRP

Revenue decoupling can improve utility incentives to adopt a wide array of initiatives to encourage cost-effective DSM and other DERs.[65] In addition to eliminating the utility's short-term incentive to increase retail sales, decoupling can reduce the utility's risk in using retail rate designs that encourage efficient DERs. For example, decoupling reduces risks of revenue loss when customers are offered time-sensitive usage charges that shift loads away from peak demand periods.

When average use is declining for any reason, decoupling reduces the needed frequency of rate cases. Decoupling also reduces controversy over billing determinants in rate cases with future test years because prices will adjust — up or down — based on actual utility sales.

A recent power industry survey found revenue decoupling in use in 14 jurisdictions.[66] DSM is aggressively encouraged by policymakers in many of these jurisdictions. Decoupling is used in tandem with MRPs in California, Minnesota and New York.

Decoupling is much more widely used by gas distributors. This reflects the fact that gas distributors have often experienced declining average use, due chiefly to external forces such as the improved efficiency of furnace technologies. Some utilities have decoupling for some services and lost revenue adjustment mechanisms (LRAMs) for others.[67]

4.3 Performance Metric Systems

Metrics (sometimes called *outputs*) quantify utility activities that matter to customers and the public.[68] These metrics can alert utility managers to key concerns, target areas of poor (or poorly incentivized) performance, and reduce costs of oversight. Target ("benchmark") values are usually established for some metrics. Performance can then be measured by comparing a utility's values for these metrics to the targets. A performance incentive mechanism links utility revenue to the outcome of one or more performance appraisals. "Scorecards" summarizing performance metric results are sometimes tabulated. These may be posted on a publicly available website or included in customer mailings.

Service Quality PIMs

Service quality PIMs are used in multiyear rate plans to improve the incentive balance between cost and quality. This can simulate connections between revenue and product quality that firms in competitive markets experience. Service quality PIMs for electric utilities have addressed both reliability and customer service.[69]

Reliability metrics have addressed systemwide reliability, reliability in subregions, and the success of restoration efforts after major storms. System reliability metrics are most likely to provide the basis for PIMs. The most common system reliability metrics are the system average interruption duration index

[65] For further discussion of revenue decoupling, see Lazar et al. (2016).
[66] Lowry, Makos and Waschbusch (2015).
[67] Electric utilities with decoupling for most customers and LRAMs for some large-volume customers include Portland General Electric, Duke Energy Ohio and AEP Ohio.
[68] Whited et al. (2015).
[69] For a survey of reliability PIMs, see Kaufmann et al. (2010). For a survey of customer service PIMs, see Kaufmann (2007).

(SAIDI) and system average interruption frequency index (SAIFI).[70] Customer service PIMs have addressed customer satisfaction, customer complaints to the regulator, telephone response times, billing accuracy, timeliness of bill adjustments, and the ability of the utility to keep its appointments.

Performance on service quality metrics is usually assessed through a comparison of a company's current year performance to its recent historical performance. Because of limited availability and lack of standardization of service quality data, benchmarking a company's performance on service quality using data from other utilities is difficult.

Demand-Side Management PIMs

Demand-side management PIMs link utility revenue to reward (or penalize) utilities for their performance on DSM initiatives. Metrics on load savings are often used in these PIMs. Compensation for load savings can take several forms:

- *Shared savings.* This approach grants the utility a share of the estimated net benefits that result from DSM. It can therefore encourage utilities to choose more cost-effective programs and manage them more efficiently. However, estimation of net benefits can be complex and controversial. *Ex post* and *ex ante* appraisals of net benefits (or a mix of the two) may be used in net benefit calculations.

- *Management fees.* This alternative grants the utility an incentive equal to a share of program expenditures. The incentive calculation depends on costs incurred (specifically, expenditures by the utility) but not on benefits achieved. Thus, the utility is rewarded for spending money, which is not necessarily well correlated to desired policy outcomes. However, the simplicity of management fees makes them an attractive option in some contexts. This approach is commonly used when net benefits are difficult to measure but are believed to be positive (e.g., public education programs), and its ease of administration has encouraged its use for other DSM programs as well.

- *Amortization.* DSM expenditures can be amortized so that the utility earns a return on them like capital expenditures. Premiums are sometimes added to the rate of return on equity (ROE) for these expenditures, and these premiums may be contingent on achieving certain DSM performance goals.

Most DSM PIMs require estimates of load savings. These savings can be estimated using engineering models, typical savings documented in technical reference manuals (deemed savings), or statistical analyses of customer billing data. Even with high-quality data, reliably estimating savings can be challenging. The complications include free riders (customers who would have implemented the efficiency measure without the program, or would have taken alternative measures), spillovers (additional savings due to the program that are not measured), and rebound effects (behavioral changes that counteract the direct effects of the program, such as using more lighting in the home because light bulbs are more efficient and thus less costly to operate).

DSM initiatives vary with respect to the difficulty of measuring load savings and the scale of expenditures that can produce material management fees and amortization. Some DSM PIMs encourage utilities to design programs with more measurable impacts or larger expenditure requirements. Other DSM initiatives that are equally or more cost-effective may be neglected. Such initiatives may include changes

[70] Other reliability metrics include the customer average interruption duration index (CAIDI) and the momentary average interruption duration index (MAIFI).

in default retail rate designs, cooperation with third-party vendors of energy services and products, support for upgraded state appliance efficiency standards and building codes, and other efforts to transform energy service markets.

Pros and Cons of Demand-Side Management PIMs

Demand-side management PIMs can be a useful addition to multiyear rate plans. Under these plans, utilities may still lack sufficiently strong incentives to encourage DSM. For example, most MRPs accord tracker treatment to fuel and purchased power expenses. Transmission costs may also be tracked. MRPs may provide some incentive to contain load-related capex, but not to levels found in unregulated markets.

Performance incentive mechanisms for DSM can strengthen utility incentives to use DSM as a cost management tool. Such PIMs also can address the utility's short-term throughput incentive in an MRP that does not include revenue decoupling or an LRAM. Well-designed demand-side management PIMs can encourage more cost-effective DSM programs.

Still, demand-side management PIMs have drawbacks. For example, they can involve complex calculations that may complicate regulatory proceedings. Shared savings PIMs are particularly complex. By motivating utilities to improve their performance in relation to specific programs, PIMs may lead to a deterioration in other aspects of DSM performance that are not measured.[71] In addition, utility rewards for load savings can sometimes become sizable over the years.

Precedents for Demand-Side Management PIMs

A 2014 survey by the Edison Foundation Institute for Electric Innovation found that DSM PIMs are quite common in the United States.[72] In all, 29 states had some form of DSM PIM. Among them, all but five had also adopted decoupling or LRAMs. Demand-side management PIMs were included in more than half of the U.S. electric MRPs identified. Among DSM PIMs, those focused on conservation and energy efficiency programs were the most common, and some states have decades of experience with them. PIMs also may address peak load management.

Despite their relative complexity, shared savings mechanisms have been the most popular PIM compensation approach for many years. However, management fees are also widely used. In some cases, regulators have approved more than one compensation approach (e.g., shared savings for programs with quantifiable benefits; management fees for education and marketing programs).

Most DSM PIMs approved to date have pertained to programs serving customers across broad areas of a utility's service territory. However, PIMs can also be targeted to specific geographic areas, such as those where substantial transmission and distribution capex will be needed in the near future to replace aging assets or accommodate growing load. We discuss some examples of these programs in Section 6.

4.4 Efficiency Carryover Mechanisms

Efficiency carryover mechanisms limit true-ups of a utility's revenue to its cost when an MRP concludes. These mechanisms encourage utilities to achieve long-term performance gains that can benefit customers after a plan's conclusion. They can also counteract some adverse incentives that can result under MRPs from periodic rate cases that set a utility's revenue requirement equal to its cost. Due to compression of

[71] New York and other jurisdictions are for this reason considering less program-specific DSM performance metrics like normalized volume per customer.
[72] Institute for Electric Innovation (2014).

the period during which benefits of long-term performance gains improve their bottom line, utilities may have less incentive in later years of a plan to limit upfront costs needed to achieve such gains. In addition, rate cases provide disincentives to contain costs that influence the revenue requirement in the first year of the next plan. For example, there may be less incentive to strike hard bargains with vendors. Given the different incentives to contain cost in early and later plan years, utilities may also be incentivized to defer certain expenditures in the early years of the plan so that these expenses show higher totals in the MRP test year. Customers may then "pay twice" for some costs that are funded by the ARM.

To counteract such incentives, efficiency carryover mechanisms can be designed that reward utilities for offering customers good value in later plans. Such mechanisms can also penalize utilities for offering customers poor value. One kind of efficiency carryover mechanism involves a comparison of revenue requirements in the test year of the next rate case to a benchmark. The mechanism may take the form of a targeted PIM. The revenue requirement in a forward test year could, for example, correspond to the following formula:

$$RR_{t+1} = Cost_{t+1} + \alpha \cdot (Benchmark_{j,t+1} - Cost_{j,t+1})$$

where α is a share of the value implied by benchmarking and takes a value between 0 and 1.[73] Variance between benchmark and actual costs can, alternatively, be used to adjust the X factor in the next plan if it has an index-based ARM.

Choice of a benchmark is an important consideration in design of this kind of efficiency carryover mechanism. One approach is to use as the benchmark the revenue requirement established by the expiring MRP (extended by one year in the case of a forward test year). Cost (or the proposed revenue requirement) may, alternatively, be compared to a benchmark based on statistical cost research which is completely independent of the utility's cost.

[73] Note that the formula allows for the possibility that only a subset (j) of the total cost is benchmarked. This could be the subset that is easier to benchmark.

Efficiency Carryover Mechanisms: An Example From New England

National Grid, a company with utilities that have long operated under MRPs in Britain, incorporated efficiency carryover mechanisms in plans for several power distributors in the northeast United States. For example, in Massachusetts, New England Electric System and Eastern Utilities Associates were in the process of merging when they were acquired by National Grid. In 2000 the Massachusetts Department of Telecommunications and Energy approved a settlement which, among other things, detailed an MRP under which the surviving power distributors of the merging companies (Massachusetts Electric and Nantucket Electric) would operate for 10 years.[74]

The settlement did not require rates to be reset in a rate case at the conclusion of the rate plan. However, the settlement limited over a 10-year "Earned Savings Period" the extent to which rates established in future rate cases could reflect the benefits of cost savings achieved during the plan. These "earned savings" were to conform to the following formula:

Earned Savings = Distribution revenue under rates applicable in March 2009

- *pro forma cost of service (COS)*

The focus on 2009 reflects the fact that Massachusetts has historical test years, so this was expected to be the first year in which cost could provide the basis for post-plan rates. During the Earned Savings Period, Massachusetts Electric was permitted to add to its cost of service during any rate case the lesser of $66 million and 100 percent of earned savings achieved in 2009 up to $43 million, plus 50 percent of any earned savings above $43 million. Thus, if there were no earned savings there would be no revenue requirement adjustment. Any earned savings would be capped at $66 million.

At the end of the plan period, National Grid requested a large revenue requirement increase. This was explained in part by the need to replace aging infrastructure. The utility did not include an allowance for earned savings in its 2009 rate request.

Regulators in Australia, Britain and Ontario routinely take an approach to cost benchmarking which uses econometric methods in rate setting. In the United States, econometric benchmarking studies have occasionally been filed by U.S. utilities. Public Service of Colorado, for example, has filed econometric benchmarking studies of its forward test year revenue requirement proposals for the cost of its gas and electric operations.[75] We discuss econometric benchmarking further in Appendix B.3.

Experience around the world with efficiency carryover mechanisms has been less extensive than experience with some other MRP provisions. Australia has been a leader, using these mechanisms in both power transmission and distribution regulation. The Alberta Utilities Commission uses efficiency carryover mechanisms in MRPs for provincial energy distributors.

[74] See Settling Parties in Massachusetts (1999).
[75] Lowry, Hovde, Kalfayan, Fourakis, and Makos (2014).
Lowry, Hovde, Getachew, and Makos (2010).
Lowry, Hovde, Getachew, and Makos (2009).

4.5 Menus of MRP Provisions

Some MRPs contain menus of provisions from which utilities can choose. Menus typically include a key ARM provision and another plan provision affecting utility finances. In a plan with an indexed ARM, a utility might, for example, have a choice between (1) a low X factor and an earnings sharing mechanism and (2) a higher X factor and no earnings sharing.

An "incentive compatible" menu incentivizes a utility to reveal, by its choice between menu options, its potential for containing cost growth. This approach to MRP design has been discussed in the academic regulatory economics literature since the 1980s. Major theoretical contributions have been made by Michael Crew, Paul Kleindorfer and Nobel prize-winning economist Jean Tirole.[76]

The Federal Communications Commission used a menu approach to MRP design in a 1990 price cap plan for interstate access services of large local telecommunications exchange carriers.[77] The menu embedded in the Information Quality Incentive of British regulators is explained in Appendix A.4.

[76] Laffont and Tirole (1993), Crew and Kleindorfer (1987), Crew and Kleindorfer (1992), and Crew and Kleindorfer (1996).
[77] Federal Communications Commission (1990).

5.0 Incentive Power Research

Pacific Economics Group has developed an Incentive Power model to explore the incentive impact of alternative regulatory systems such as multiyear rate plans. The model addresses the situation of a hypothetical energy distributor that has several kinds of initiatives available to improve its cost performance. Using numerical analysis, the model can predict the cost savings that will occur under various regulatory systems. The regulatory systems considered are stylized but resemble real-world options in use today. Appendix B.1 provides details of the research.

Key results of our incentive power research include the following:

- *Cost containment incentives depend on the frequency of rate cases.* Today, utilities in the United States typically hold rate cases every three years.[78] For a utility with normal operating efficiency, our model finds that long-run cost performance on average improves 0.51 percent more rapidly each year in an MRP with a five-year term and no earnings sharing than it does under traditional regulation when rate cases occur every three years. This means that cost will be about 5 percent lower after 10 years under the MRP. For a utility with an annual revenue requirement of $1 billion, this would be an annual cost saving of $50 million in real terms.

- *If rate cases under traditional regulation occur more frequently, the incremental incentive impact of an MRP is higher.* For example, the long-run impact of MRPs with five-year terms is 0.75 percent additional annual cost containment if rate cases would otherwise be held every two (rather than three) years. This kind of comparison is more relevant to regulators when the alternative to an MRP is frequent rate cases or extensive use of cost trackers.

- *Earnings sharing mechanisms weaken incentives produced by an MRP.* For example, MRPs with a five-year term and 75/25 sharing of all earnings variances between utilities and their customers produce only 0.27 (rather than 0.51) percent annual performance gains compared to a three-year rate case cycle.

- *Performance gains from more incentivized regulatory systems are greater (smaller) for companies with a low (high) initial level of operating efficiency.*

- *Incentives generated by an MRP can be materially strengthened by a well-designed efficiency carryover mechanism or system of menu options.* Suppose, for example, that when rates are rebased the utility absorbs 10 percent of the variance between its own cost and a statistical benchmark of cost. Our model finds that annual performance gains increase by 90 basis points in a plan with a five-year term relative to those from traditional regulation with a three-year rate case cycle. This means a 9 percent lower cost after 10 years.

Our incentive power research has a number of implications. It shows that a utility's performance incentives and performance can be materially affected by the regulatory system under which it operates. This means that more incentivized regulatory systems such as well-designed MRPs can provide material cost savings that can be shared between utilities and their customers. New MRP design provisions such as efficiency carryover mechanisms and menu options can materially increase incentive power.

[78] Lowry and Hovde (2016), p. 44.

Utility performance is materially affected by the frequency of rate cases, and the frequency of rate cases is affected by the adversity of business conditions. Our incentive power research thus supports the notion that performance of utilities under COSR tends to decline under adverse business conditions. When business conditions are adverse, regulators should be especially vigilant about utility operating prudence and consider how to strengthen performance incentives. That can be particularly important given that utilities typically advocate for expedited recovery of their costs when business conditions are adverse, and often are successful.

6.0 Case Studies

This section presents case studies of multiyear rate plans. Each case study discusses the nature of MRPs enacted, identifying important provisions and controversies and rationales for utility regulators to choose PBR. We also consider effects of PBR on cost performance using power distributor productivity indexes. These indexes consider productivity in the provision of customer services such as billing and distribution services. We compare productivity trends of utilities operating under rate plans, or less formal rate case stayouts, to contemporaneous utility norms. Appendix B.2 provides details of our utility productivity research.

6.1 Central Maine Power

The Maine Public Utilities Commission was for many years a leader in energy utility PBR.[79] Central Maine Power (CMP) is Maine's largest electric utility. From 1995 to 2013, it operated under a succession of three MRPs called *alternative rate plans.* Full rate cases did not occur between plans. The first plan took place while the company was still vertically integrated, while later plans applied to CMP's distributor services after restructuring. All three plans were outcomes of settlements between CMP and other parties.

In a 1993 rate case decision, the Commission encouraged CMP to operate under an alternative rate plan. This decision took into consideration CMP's recent history of rapid rate escalation and losses of margins from large-volume customers. The Commission expressed concern that CMP's management had spent "greater attention on a reactive strategy of deflecting blame than on proactively cutting costs."[80] The Commission also noted in its decision general problems with continued use of traditional regulation for CMP. These problems included:

> 1) the weak incentive provided to CMP for efficient operation and investments; 2) the high administrative costs for the Commission and intervening parties from the continuous filing of requests for rate changes; 3) CMP's ability to pass through to its customers the risks associated with a weak economy and questionable management decisions and actions; 4) limited pricing flexibility on a case-by-case basis, making it difficult for CMP to prevent sales losses to competing electricity and energy suppliers; and 5) the general incompatibility of traditional [COSR] with growing competition in the electric power industry.[81]

The Commission outlined its views of potential costs and benefits of MRPs (presumed to feature price caps) in its decision:

> Based on the evidence presented in this proceeding, the Commission finds that multi-year price-cap plans is [sic] likely to provide a number of potential benefits: (1) electricity prices continue to be regulated in a comprehensible and predictable way; (2) rate predictability and stability are more likely; (3) regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations; (4) Risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial

[79] Thomas Welch, a former telecommunications lawyer, chaired the Commission during these years.
[80] Maine Public Utilities Commission (1993), pp. 14–15.
[81] Maine Public Utilities Commission (1993), p. 126.

> perspective); and (5) because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created.[82]

The decision discussed the marketing flexibility benefits of MRPs at some length:

> Price caps coupled with pricing flexibility allow a regulated firm to compete on a more equal basis with other suppliers that threaten its markets: a firm is given wide pricing discretion and the opportunity to offer new services in the absence of case-by-case regulatory approval.
>
> An important benefit of price caps lies with protecting the so-called "core customers" from competition encountered in other markets. For example, if separate price caps are placed on each class of customer, whatever revenues the utility earns in the more competitive industrial markets would not directly affect the price it can charge (say) residential customers… In contrast, under [COSR] a firm is generally given the opportunity to receive revenues corresponding to its revenue requirement. This implies that whenever the firm receives fewer revenues from one group of customers, it would have the right to petition for increased revenues from others by proposing to raise their prices….[83]

Plan Designs

Attrition Relief Mechanism

All three of CMP's plans featured price caps with index-based escalators. The caps applied to both base and energy rates for vertically integrated service in the first plan, and to base rates for distributor services in later plans. Evidence on input price and productivity trends of Northeastern U.S. electric utilities was presented and debated in each proceeding to inform the choice of an X factor.[84] Macroeconomic price indexes were used as inflation measures. The accuracy of such measures as proxies for utility input price inflation was a prominent issue in one proceeding.

Marketing Flexibility

When CMP was vertically integrated, it had a special need for flexibility in its marketing to pulp and paper customers, some of whom had cogeneration options or were economically marginal, or both. Maine's legislature passed a law allowing the Commission to authorize pricing flexibility plans which permit utilities to discount their rates with limited or no Commission approval. The Commission also encouraged utilities to develop special contracts with customers.

The Commission noted the following in approving the first alternative rate plan for CMP:

Because CMP will have substantial exposure to revenue losses due to discounting, the Company will have a strong incentive to avoid giving unnecessary discounts, and it will have a strong incentive to find cost savings to offset any such losses. Pricing flexibility gives CMP the opportunity to use price to compete to retain customers.[85]

[82] Maine Public Utilities Commission (1993), p. 130.
[83] Maine Public Utilities Commission (1993), p. 130.
[84] X factors in Maine were commonly referred to as "productivity offsets."
[85] Maine Public Utilities Commission (1995), p. 19.

Marketing flexibility provisions in this plan included these features:

- For core customers, CMP was free to set rates between the rate cap and a rate floor based on an estimate of long-term marginal cost.
- CMP could receive expedited approval of new targeted services.
- CMP could also receive expedited approval of special rate contracts with individual customers. Different provisions applied for short-term and long-term contracts.
- Revenue lost during a plan as a result of discounts was recoverable from other customers only through the earnings sharing mechanism (ESM). In the first plan, a cap of 15 percent was placed on overall lost revenues that could be recovered through the ESM.

Subsequent plans did not make substantial changes to these pricing flexibility provisions.

Other Plan Provisions

Earnings sharing mechanisms and penalty-only service quality PIMs were included in all three plans. Service quality benchmarks for these PIMs became more demanding over time.

The first-generation plan also featured a tracker for DSM costs and a DSM PIM. These latter features were subsequently removed with restructuring and establishment of a third-party DSM program administrator in Maine.

Outcomes

Cost Performance

Table 4 and Figure 6 compare the trends in O&M, capital and multifactor productivity of the company's power distributor services to the average for U.S. electric utilities in our sample from 1980 to 2014. The table shows that from 1980 to 1995, before MRP regulation, the company's MFP growth was a little slower than that of the full sample on average. Over the 1996 to 2013 period during which CMP operated under alternative rate plans, it averaged 0.92 percent annual MFP growth, while the full sample of U.S. electric utilities averaged 0.42 percent annual MFP growth. The MFP growth differential thus averaged 50 basis points. Table 4 also shows that CMP accomplished this through much more rapid *capital* productivity growth. This is notable given the interest of many regulators today with capex containment. O&M productivity trends of CMP and the sample were more similar.

Nuclear Problems

At the start of PBR, when CMP was still vertically integrated, it owned 38 percent of Maine Yankee Atomic Power Co., owner and operator of a nuclear generating station. CMP relied on this station for a sizable share of its power supply. The station experienced an extended outage during the plan. The plan did not fully compensate CMP for the increased costs for repairs, decommissioning and purchased power expenses that resulted from the Maine Yankee outage. This resulted in lower earnings for CMP, which in 1998 triggered the lower bound of the ESM.

Table 4. How Productivity Growth of Central Maine Power Compared to That of Other U.S. Electric Utilities: 1980–2014*

Year	CMP			U.S. Average		
	MFP	PFP O&M	PFP Capital	MFP	PFP O&M	PFP Capital
1980	-0.17%	-2.17%	1.08%	-0.49%	-4.19%	1.24%
1981	0.45%	-3.00%	1.47%	0.17%	-2.42%	1.25%
1982	0.08%	-1.43%	1.84%	0.87%	-1.20%	1.53%
1983	0.42%	-2.22%	1.82%	0.51%	-0.38%	0.98%
1984	1.63%	1.28%	1.80%	1.27%	-0.22%	1.79%
1985	0.75%	-1.94%	1.94%	0.95%	-0.21%	1.37%
1986	2.08%	0.89%	2.57%	0.91%	0.88%	0.97%
1987	0.59%	-1.10%	1.28%	0.44%	-0.12%	0.68%
1988	-0.49%	-1.43%	-0.03%	0.57%	1.55%	0.24%
1989	-0.83%	-0.12%	-1.25%	0.26%	0.00%	0.23%
1990	-0.97%	0.24%	-1.79%	0.18%	0.64%	-0.05%
1991	-0.43%	1.04%	-1.39%	-0.03%	0.58%	-0.32%
1992	1.32%	2.51%	0.64%	0.48%	1.61%	0.10%
1993	-0.24%	-2.55%	1.04%	0.45%	1.19%	0.12%
1994	2.10%	2.87%	1.66%	0.94%	2.44%	0.29%
1995	1.80%	0.98%	2.30%	0.94%	3.58%	-0.04%
1996	1.67%	1.75%	1.62%	0.11%	0.67%	-0.13%
1997	1.08%	-0.40%	2.00%	1.53%	4.68%	0.39%
1998	0.17%	-2.94%	2.14%	0.67%	0.73%	0.71%
1999	2.03%	1.98%	2.05%	1.08%	2.24%	0.52%
2000	0.97%	-2.17%	2.18%	0.89%	0.86%	0.73%
2001	0.83%	-0.69%	1.80%	1.20%	2.73%	0.61%
2002	1.23%	1.28%	1.19%	0.79%	2.73%	0.33%
2003	1.35%	-0.49%	2.83%	-0.03%	-1.50%	0.43%
2004	-0.35%	-3.96%	2.56%	0.41%	0.76%	0.22%
2005	1.85%	1.27%	2.32%	-0.07%	-0.25%	0.09%
2006	1.02%	-0.48%	2.62%	-0.52%	-1.07%	-0.21%
2007	1.16%	-0.21%	3.12%	-0.12%	0.00%	-0.02%
2008	-1.51%	-2.67%	1.27%	-0.99%	-2.06%	-0.09%
2009	2.23%	2.57%	1.34%	1.01%	2.73%	-0.46%
2010	-0.51%	-1.65%	1.00%	-0.27%	-0.47%	0.05%
2011	3.54%	6.17%	0.85%	0.50%	0.05%	0.50%
2012	0.56%	1.86%	-0.63%	1.29%	2.90%	0.58%
2013	-0.73%	-2.31%	0.76%	0.03%	0.40%	-0.05%
2014	-1.61%	-4.74%	1.47%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.66%**	**-0.34%**	**1.36%**	**0.45%**	**0.53%**	**0.43%**
1980-1995	**0.51%**	**-0.39%**	**0.94%**	**0.53%**	**0.23%**	**0.65%**
1996-2013	**0.92%**	**-0.06%**	**1.72%**	**0.42%**	**0.90%**	**0.23%**
2008-2014	**0.28%**	**-0.11%**	**0.86%**	**0.22%**	**0.30%**	**0.15%**

*CMP operated under multiyear rate plans in the years for which results are shaded.

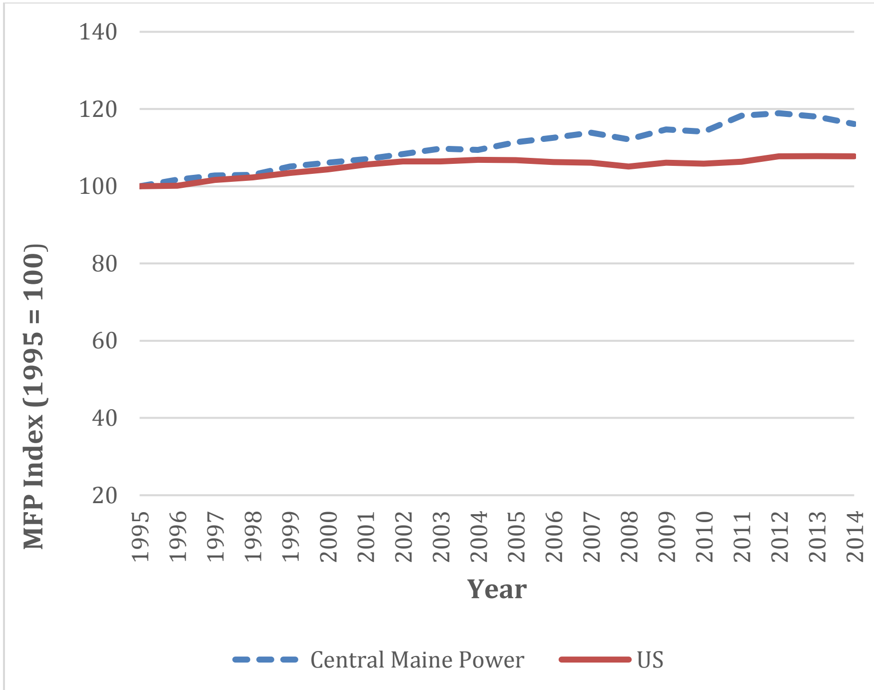

Figure 6. Comparison of Multifactor Productivity Trends of Central Maine Power and the U.S. Sample During Multiyear Rate Plan Periods. The MFP growth of CMP exceeded the industry norm during MRPs.

Marketing Flexibility

During its first rate plan, CMP entered into special contracts with 18 large customers. These contracts featured discounts from tariffed rates in exchange for a guarantee that customers would not attempt to shift their loads to competitors or self-generate during the contract term. In its 1999 10-K filing with the Securities Exchange Commission, CMP described the importance of pricing flexibility and its impacts on the company:

Central Maine believes that without offering the competitive pricing provided in the agreements, a number of these customers would be likely to install additional self-generation or take other steps to decrease their electricity purchases from Central Maine. The revenue loss from such a usage shift could have been substantial.[86]

Service Quality

During the second of CMP's three plans, the Energy and Utilities Committee of Maine's Legislature asked the Public Utilities Commission to investigate effects of the rate plans on service quality performance. This review ultimately resulted in a third-party report.[87] Results of this review were mixed. CMP generally met or exceeded service quality targets. However, performance was uneven. Feeders serving densely populated areas like Portland received greater attention, and these feeders had a greater effect on measured performance systemwide than feeders in rural areas. These performance differences may reflect the fact that reliability PIMs measured only systemwide performance and did not measure performance at a more granular level.

[86] Central Maine Power (1998), p. 81.
[87] Williams Consulting (2007).

Current Status

In 2013, near the conclusion of its third plan, CMP proposed a fourth-generation plan that would have significantly accelerated its revenue growth to help fund a forecasted capex surge.[88] Table 4 shows that CMP's capital productivity trend slowed after 2007. The case ended in a settlement that returned the company to a more traditional regulatory system.[89] A capital tracker for a new customer information system was approved, as was revenue decoupling. While service quality PIMs and the ESM no longer apply, pricing flexibility has continued. No rate case has subsequently been filed.

6.2 California

The California Public Utilities Commission (CPUC) has extensive experience with PBR. This includes the longest experience in North America with MRPs for retail energy utility services. The CPUC has jurisdiction over an energy utility industry that in North America is second in size only to that under the jurisdiction of the Federal Energy Regulatory Commission. Six investor-owned electric utilities (two of which are very large) are regulated, along with natural gas, telecommunications, water, railroad, rail transit and passenger transportation companies. This gives the CPUC strong incentives to contain regulatory costs. MRPs were also facilitated by the CPUC's routine use of forward test years. California's power market was restructured in the 1990s, but two of three large, jurisdictional electric utilities have continued to have sizable generation operations.

The CPUC has limited the frequency of general rate cases using rate case plans for decades. Rate cases were staggered to reduce the chance that the CPUC had to consider cases for multiple large utilities simultaneously. A two-year plan for Southern California Edison was approved in 1980. The standard lag between rate cases was increased to three years in 1984. Longer (e.g., four- or five-year) rate case cycles have since been approved on several occasions.

The CPUC has not always characterized its plans as PBR but did acknowledge the merits of PBR in a 1994 order:

We intend to replace cost-of-service regulation with performance-based regulation. Doing so neither changes the [regulatory] compact's tenets, nor threatens fulfillment of those tenets. We make this change for several reasons.

> First, prices for electric services in California are simply too high. The shift to performance-based regulation can provide considerably stronger incentives for efficient utility operations and investment, lower rates, and result in more reasonable, competitive prices for California's consumers. Performance-based regulation also promises to simplify regulation and reduce administrative burdens in the long term. Second, since the utilities' performance-based proposals currently before us leave both industry structure and the utility franchise fundamentally intact, consumers can expect service, safety and reliability to remain at their historically high levels. Third, the utilities' reform proposals are likely to provide an opportunity to earn that is at a minimum comparable to opportunities present in cost-of-service regulation. Finally, performance-based regulation can assist the utilities in developing the tools necessary to make the successful transition from an operating environment directed by government and focused on regulatory proceedings, to one in which consumers, the rules of competition, and market forces dictate. This is of critical importance in our view.[90]

[88] The Commission stated its opposition to a new plan with a hybrid ARM based on a capital cost forecast.
[89] Maine Public Utilities Commission (2014).
[90] California PUC (1994), pp. 34–35.

The CPUC also has been a national leader in revenue decoupling and PIMs for DSM. This makes California a good case study of the impact performance-based regulation can have on utility DSM as well as cost management. The evolution of MRP design in the state is of further interest given its long history and the diverse situations to which plans have applied.

Plan Design

Attrition Relief Mechanisms

Establishment of multiyear rate case cycles for California energy utilities raised issues of whether and how rates could be adjusted between rate cases. Utilities in the early 1980s were subject to cost pressures from inflation and capacity growth. The three largest utilities invested in nuclear power plants but were denied permission to fund their (often delayed) construction by charging for a return on construction work in progress. The CPUC encouraged large-scale purchases of power from non-utility generators. Revenue decoupling insulated utilities from risks of demand fluctuations but denied them extra revenue from growth in sales volumes, numbers of customers served, and other billing determinants.

Under these circumstances, the CPUC acknowledged that escalation of revenue is typically needed between rate cases.[91] ARMs were thus permitted,[92] and energy costs were addressed by trackers. The out-years of the rate case cycle came to be called *attrition years.* Various approaches to ARM design have been used over the years in California. Predetermined "stepped rate" increases were approved in 1980.[93] However, high inflation encouraged use of inflation measures in ARMs, and many subsequent California ARMs have provided some automatic inflation relief. A hybrid approach to ARM design has been used on many occasions. The broad outline of the first ARMs for Pacific Gas and Electric (PG&E), which started in 1981, is remarkably similar to that of hybrid ARMs that are still occasionally used today.[94]

- O&M expenses were escalated only for inflation. The CPUC implicitly acknowledged that growth in productivity and operating scale also drive cost escalation but assumed that their impact was offsetting.[95]

- Capex per customer was fixed in constant dollars at a five-year average of recent net plant additions, then escalated for inflation.

- Other components of capital cost, like depreciation and return on rate base, were forecasted using cost of service methods. Subsequent hybrid ARMs used in California have involved variations on this basic theme. For example, capex budgets have occasionally been fixed in real terms for several years at forward test year value, then escalated for construction cost inflation. Detailed indexes of utility O&M input price inflation have replaced indexes of

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[91] The CPUC has nevertheless persistently maintained that attrition adjustments are not an entitlement even under revenue decoupling and has occasionally rejected their implementation. See, for example, the rejection of PG&E's 2002 attrition adjustment in D.03-03-034.
[92] The ARM was sometimes called an Attrition Relief Adjustment and has in recent years been called a post-test-year mechanism.
[93] California PUC D. 92497 (1980a) for Southern California Gas and California PUC D. 92549 (1980b) for Southern California Edison.
[94] Hybrid ARMs are frequently featured by utilities in their post-test year proposals.
[95] "Our labor and nonlabor costs adopted for test year 1982 will be escalated by appropriate inflation factors for labor and nonlabor expenses…. We will not adopt a growth factor but assume that any growth or increase in activity levels will be offset by increased productivity and efficiency." California PUC (1981) Cal. PUC LEXIS 1279; 7CPUC 2d 349.

macroeconomic price inflation in escalation of revenue requirements for O&M expenses. Some plans have permitted utilities to escalate their labor revenue to reflect wage growth in their union contracts.

Several utilities experimented with fully indexed ARMs between 1998 and 2007. For example, PG&E, Southern California Edison, and San Diego Gas & Electric all operated under indexed ARMs.[96] Southern California Gas, America's largest gas distributor, operated under a revenue-per-customer index with inflation and X factor terms. Larger utilities have in recent years most commonly operated under revenue caps with comprehensive stair step escalators. Cost trackers have provided supplemental revenue for advanced metering infrastructure and some reliability-related capex.

Revenue Decoupling

Revenue decoupling has often been used in conjunction with California multiyear rate plans to reduce utilities' incentives to boost retail sales. Revenue decoupling mechanisms called *supply adjustment mechanisms* were first instituted for gas distributors in the late 1970s at the conclusion of a generic proceeding.[97] By 1982, the CPUC approved revenue decoupling mechanisms (called *Electric Revenue Adjustment Mechanisms*) for the three largest California electric utilities. The appeal of decoupling for electric utilities came from several sources:

- Power conservation became a priority in the state in the 1970s, spurred by generation capacity concerns and high fuel prices.[98] The CPUC declared in 1976 that "Conservation is to rank at least equally with supply as a primary commitment and obligation of a public utility."[99] Utilities played a large role in administering DSM programs (and still do).

- Electric utilities had experimental rate designs such as inverted block rates that were intended to promote conservation but increased sensitivity of utility earnings to demand shifts.

- Utilities experienced substantial risk from other sources, including multiyear rate plans and the CPUC's unwillingness to grant funding for nuclear plant construction work in progress.

Despite a generally positive experience, use of decoupling for California electric utilities fell off in the mid 1990s due, in part, to rules governing the transition to retail competition. There was also some thought that DSM might be provided in the future by independent marketers. A return to decoupling was mandated in 2001 by state legislation motivated in part by the need to promote conservation and contain utility risk during the California power crisis.[100] The three largest electric utilities recommenced decoupling, which continues today.

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[96] Indexed ARMs are still used for California energy utilities serving smaller state loads. For example, a 2007 decision in a PacifiCorp rate case approved a settlement that outlined an MRP featuring a price cap index and a three-year term. The index has escalated base rates to reflect growth in an annual forecast of CPI less a productivity adjustment of 0.5 percent. Supplemental revenue is permitted for the California portion of major plant addition costs exceeding $50 million. Parties later agreed to defer PacifiCorp's scheduled 2010 rate case for one year and adopted an identical MRP in the 2011 general rate case. The CPUC agreed to extend PacifiCorp's renewed MRP for several additional years, and the utility will not file a new rate case until 2019 at the earliest.

[97] CPUC Decision 88835, Case No. 10261, May 1978.

[98] Fossil fueled generators in California burned oil, gas or both.

[99] CPUC Decision 85559, March 1976, p. 489.

[100] See California Public Utilities Code (2001).

Demand-Side Management PIMs

California was also an early innovator in the area of DSM PIMs. The first experimental DSM PIMs were implemented in 1990. These measures did not survive deregulation of California's electricity market later in the decade.

In 2007, California reintroduced DSM PIMs for larger utilities through the Risk-Reward Incentive Mechanism. This mechanism featured a relatively complex shared savings approach to compensation. Each utility had targets for three metrics (if applicable): electricity savings, gas savings and peak demand reductions. Under the original incentive design, utilities could receive a reward of up to 12 percent of the dollar value of evaluated net benefits of eligible DSM programs if they performed strongly on all three metrics. Conversely, they would be penalized if they fell below 65 percent of the target for any one of the three metrics. Critically, utility financial outcomes would be based on evaluated (*ex post*), not predicted (*ex ante*), net benefits. That meant that utility outcomes were not known until program evaluations were completed. This choice extended the process and added complexity. However, the CPUC felt it important to reward or penalize how programs actually performed in order to properly align utility incentives and protect ratepayers from adverse outcomes.[101]

The Risk-Reward Incentive Mechanism was implemented for the first time at the end of the 2006–2008 utility program cycle. Disputes over net benefits soon developed, as the CPUC's evaluation consultants estimated program results that substantially differed from the utilities' estimates and implied very different financial outcomes, in part due to the sharp earnings cutoffs in the mechanism's reward structure.[102] Disputes stretched over several years and proved intractable enough that the CPUC modified the mechanism. It based net benefit calculations on parameters (for example, net-to-gross ratios) estimated before programs were implemented, as well as on actual program delivery outcomes.[103] It also lowered the incentive to a flat 7 percent of net benefits and eliminated the possibility of penalties. Savings used to calculate rewards were in between the utilities' and the CPUC's estimates. For programs from 2010 to 2012, the CPUC simplified these PIMs, establishing rewards conditioned primarily on utility spending (management fees) rather than evaluated program performance.

In 2013, the CPUC adopted the Energy Savings Performance Incentive.[104] Under this mechanism, performance awards for many programs were based on energy savings delivered, not net benefits. Energy savings were not discounted, unlike energy benefits in the earlier net benefits calculation. Thus, the revised mechanism provided greater relative rewards for deeper, longer-lived savings. The revised mechanism did not include a potential penalty and avoided sharp earnings cutoffs of the Risk-Reward Incentive Mechanism. Rewards under the Energy Savings Performance Incentive were expected to be lower, and the incentive also capped the maximum achievable reward at a lower level, compared to the Risk-Reward Incentive Mechanism, largely due to the absence of an earnings penalty.

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[101] See CPUC, 2007b, Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs, http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf.

[102] The reward/penalty function consisted of four tiers: a penalty if evaluated energy/capacity savings were less than 65 percent of a target; a dead band of no reward or penalty if savings were between 65 percent and 85 percent of a target; a 9 percent shared savings reward if savings were between 85 percent and 100 percent of a target; and a 12 percent shared savings reward if savings exceeded a target. Each transition between tiers created a sharp reward discontinuity. A small change in the evaluated savings could produce a big change in the reward. Further exacerbating these issues, a utility was paid based on the worst of the three outcomes. For example, if a utility fell below 65 percent of any of the three targets, it earned a penalty even if it performed strongly on the other two. In one case, a utility's estimated savings implied a $180 million reward; the evaluation consultants' estimates implied a $75 million penalty. See Chandrashekeran et al. (2015).

[103] This CPUC decision was controversial, with one commissioner objecting that the revised mechanism largely eliminated the actual performance incentives and ratepayer protections provided by the prior, *ex post*-based mechanism. See http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128882.pdf.

[104] CPUC (2013).

The Energy Savings Performance Incentive calculates savings *ex post*, reintroducing one of the challenges under the previous incentive mechanism. Some parameters that are considered relatively certain were locked in *ex ante*; those deemed "sufficiently uncertain" by the CPUC required *ex post* measurement. In reintroducing *ex post* calculations, the CPUC emphasized the need to protect ratepayers from paying out rewards based on overly optimistic *ex ante* projections, arguing that this objective outweighed the utilities' desire for revenue certainty and justified potential disputes over *ex post* savings calculations. The Energy Savings Performance Incentive rewarded both codes and standards support programs and "non-resource" programs (those that cannot support an energy savings calculation — largely market transformation programs) using a management fee based on utility dollars spent. The Risk-Reward Incentive Mechanism had not rewarded these programs. Incentives distributed for 2013 and 2014, as well as some rewards for 2015, have prompted far fewer disputes over process and savings estimates.

The CPUC recently developed a pilot PIM program for DERs such as distributed generation and storage. The CPUC approved a management fee mechanism that would offer investor-owned electric utilities 4 percent of annual payments made to DER providers pretax as an incentive to use third-party DERs to cost-effectively displace or defer the need for capex for traditional distribution system investments that were previously planned and authorized.[105] Utilities are required to pursue at least one project and have the option to pursue three more.

The CPUC also authorized the utilities to keep any savings from capex underspends due to DER that had been previously approved until the next general rate case.[106] Estimated costs of the DER and administration of the solicitation are recoverable with interest up to a preapproved cap when rates are reset in the next rate case. Administrative costs above the cap will be reviewed for reasonableness in the next rate case.

In their procurement decisions, utilities are required to consider the net market value of potential DER pilot projects. The net market value calculation includes a broad range of factors, including capacity, energy, ancillary grid services, costs of grid integration, deferred distribution and transmission system costs, and the cost of the DER procurement contract. During the pilot, each of the three major electric utilities are allowed to use different methods for ensuring that DERs rewarded by the incentive are incremental to the utility's existing plans and efforts as governed by other Commission proceedings, in order to test the performance of each method.

Other MRP Provisions

Other characteristics of California electric utility regulation also merit note:

- The CPUC decided in Decision 89-01-040 to address target rates of return on capital of all energy utilities in a separate annual proceeding. This meant that revenue requirements generated by ARMs often have been subject to supplemental rate of return adjustments. Some of these adjustments have been formulaic.[107]

[105] California PUC (2016).
[106] This is not a change from current California regulatory practices, but was explicitly stated nonetheless.
[107] For example, San Diego Gas & Electric's Market Indexed Capital Adjustment Mechanism, approved in 1996, featured a trigger mechanism that updated the cost of capital if bond yields deviated from the benchmark by a specific amount. A similar mechanism was established in 2008 for all large California utilities.

- Cost allocation and rate design issues are commonly addressed in a second phase of a general rate case. In attrition years, utilities have additional opportunities to adjust cost allocations and rate designs in rate design "windows."[108]

- Use of capital cost trackers has been limited in California, due in part to the fact that hybrid and forecasted ARMs have been prevalent. Several plans have permitted separate treatment of discrete major plant additions such as those for power plants and AMI.

- The CPUC has experimented with incentivized trackers for generation fuel and purchased power expenses. For example, San Diego Gas and Electric had a PIM that assessed the effectiveness of its generation and dispatch costs through simulations of annual production costs using expected and actual data. PIMs also have been used for nuclear generation plant capacity factors where sharing of energy cost variances would occur if the capacity factor of a facility was above or below the dead band.

- The CPUC has approved MRPs for generating facilities, independent of other utility assets. For example, in the late 1980s, the CPUC approved an MRP for PG&E's Diablo Canyon nuclear plant where it was permitted to charge an escalating price per MWh for power produced. This charge initially compensated PG&E for capital costs as well as O&M expenses,[109] strengthening the company's incentive to keep the plan running. The Diablo Canyon rate plan expired in 2001.

- Earnings sharing mechanisms and PIMs for service quality have not been routinely featured in California MRPs. During the experimentation with index-based ARMs, earnings sharing mechanisms and service quality PIMs were more common. The CPUC has monitored service quality performance since at least the 1990s.

Outcomes

<u>Cost Control</u>

Table 5 and Figure 7 compare the distributor productivity trends of California's three largest electric utilities to the norm for our full U.S. electric utility sample. Over the full 1986–2014 period during which MRPs have been extensively used in California, the MFP growth of these utilities averaged a 0.14 percent annual *decline,* whereas the MFP of our full U.S. sample averaged 0.43 percent annual *growth.*[110] Thus, the MFP growth of the California utilities was 57 basis points *slower* on average. All three utilities had subpar trends. The capital productivity growth of California utilities has been especially slow. In the 1980–1985 period, before MRPs were widely used, MFP trends of these utilities and the full sample were similar.

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[108] Any attrition relief adjustment that the ARM puts in motion is pooled with certain other revenue requirement adjustments and recovered in advice letter filings using the Phase II cost allocations, as amended by changes effected in the rate design windows.
[109] In 1997, however, the plan was revised so that the mechanism recovered only the incremental costs of the plant (costs of O&M and new plant additions). The ongoing recovery of sunk costs was achieved through a separate transition charge.
[110] The MFP growth trends of California utilities were fairly similar to those for the full sample during the six-year 1980 to 1985 period before MRPs became common.

These unflattering results may reflect special California operating challenges. However, the results may also reflect ineffective plan design. We have noted that California ARMs have often based a utility's budget for plant additions on its own historical additions, and passed through the escalation of a utility's union wages.

Table 5. How the Power Distributor Productivity Growth of Larger California Utilities Compared to That of Other U.S. Electric Utilities: 1980–2014*

	California Average			U.S. Sample Average		
	MFP	**O&M PFP**	**Capital PFP**	**MFP**	**O&M PFP**	**Capital PFP**
1980	-0.10%	-2.39%	0.96%	-0.49%	-4.19%	1.24%
1981	0.65%	-0.85%	1.22%	0.17%	-2.42%	1.25%
1982	-0.54%	-3.92%	0.78%	0.87%	-1.20%	1.53%
1983	-0.20%	-3.46%	0.99%	0.51%	-0.38%	0.98%
1984	1.43%	-0.20%	2.00%	1.27%	-0.22%	1.79%
1985	1.27%	-1.44%	1.78%	0.95%	-0.21%	1.37%
1986	0.96%	2.23%	0.61%	0.91%	0.88%	0.97%
1987	0.58%	2.56%	0.02%	0.44%	-0.12%	0.68%
1988	1.86%	10.04%	-0.35%	0.57%	1.55%	0.24%
1989	0.80%	3.51%	-0.04%	0.26%	0.00%	0.23%
1990	0.35%	3.49%	-0.71%	0.18%	0.64%	-0.05%
1991	-1.13%	-0.85%	-1.18%	-0.03%	0.58%	-0.32%
1992	-0.71%	0.98%	-1.26%	0.48%	1.61%	0.10%
1993	-1.45%	-1.66%	-1.38%	0.45%	1.19%	0.12%
1994	0.01%	3.17%	-0.93%	0.94%	2.44%	0.29%
1995	0.27%	0.02%	0.32%	0.94%	3.58%	-0.04%
1996	1.43%	3.26%	0.89%	0.11%	0.67%	-0.13%
1997	0.41%	-1.07%	0.87%	1.53%	4.68%	0.39%
1998	-0.24%	-1.81%	0.32%	0.67%	0.73%	0.71%
1999	-0.53%	1.21%	-1.08%	1.08%	2.24%	0.52%
2000	-0.32%	1.19%	-0.92%	0.89%	0.86%	0.73%
2001	1.63%	1.41%	1.76%	1.20%	2.73%	0.61%
2002	-1.21%	-3.73%	-0.45%	0.79%	2.73%	0.33%
2003	-1.21%	-3.63%	-0.29%	-0.03%	-1.50%	0.43%
2004	-0.14%	0.34%	-0.31%	0.41%	0.76%	0.22%
2005	-0.90%	-2.64%	-0.12%	-0.07%	-0.25%	0.09%
2006	-1.36%	-3.95%	-0.06%	-0.52%	-1.07%	-0.21%
2007	-0.57%	-0.56%	-0.58%	-0.12%	0.00%	-0.02%
2008	-1.44%	-2.17%	-0.80%	-0.99%	-2.06%	-0.09%
2009	0.83%	2.22%	-0.56%	1.01%	2.73%	-0.46%
2010	-1.15%	-0.58%	-1.47%	-0.27%	-0.47%	0.05%
2011	-1.94%	-1.12%	-2.29%	0.50%	0.05%	0.50%
2012	-0.39%	0.82%	-0.91%	1.29%	2.90%	0.58%
2013	1.33%	3.94%	0.23%	0.03%	0.40%	-0.05%
2014	0.04%	3.81%	-1.28%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**-0.05%**	**0.23%**	**-0.12%**	**0.45%**	**0.53%**	**0.43%**
1980-1985	**0.42%**	**-2.04%**	**1.29%**	**0.55%**	**-1.44%**	**1.36%**
1986-2014	**-0.14%**	**0.70%**	**-0.41%**	**0.43%**	**0.93%**	**0.24%**
2008-2014	**-0.39%**	**0.99%**	**-1.01%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs were in effect.

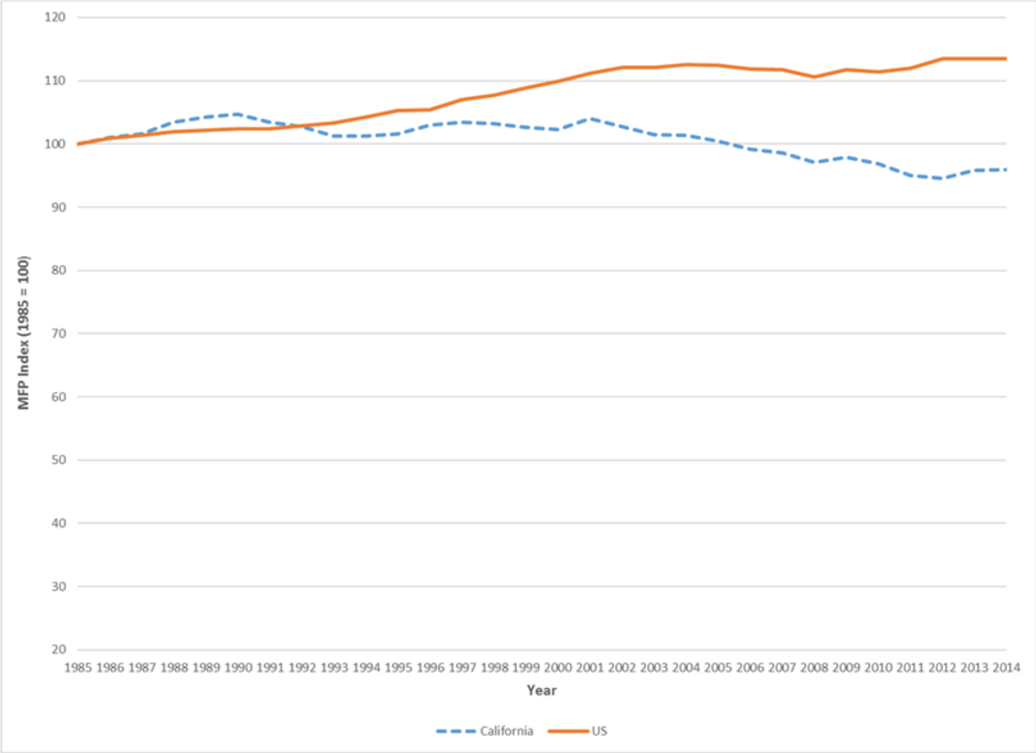

Figure 7. Comparison of Multifactor Productivity Trends of California Distributors and the U.S. Sample during Multiyear Rate Plan Periods. MFP growth of California utilities has fallen short of industry norms under MRPs.

DSM Programs

California electric utilities have typically operated large DSM programs, traditionally ranked near the top of most surveys. Since 1996, the American Council for an Energy-Efficient Economy (ACEEE) has issued annual scorecards evaluating state efforts and achievements in energy efficiency.[111] These surveys include estimates of DSM spending (or budgets) as a percentage of utility revenue. In the eight years for which data were available since 2006, California has averaged a 5.5 ranking out of 51 U.S. jurisdictions (with 1 the highest possible ranking).

Rate Designs

California has also been a national leader in use of rate designs that encourage DSM. For example, inclining block rate designs intended to encourage conservation have been mandated for residential customers since 1976.[112] Until recently, California investor-owned utilities (IOUs) had a very steep inclining block rate structure for these customers, consisting of four tiers ranging from $0.13/kWh for the lowest tier of usage to $0.42/kWh for the highest tier.[113] In a 2015 decision,[114] the CPUC reduced the number of tiers to two (plus a third tier for very high energy users) and specified that the second tier's price should be 25 percent higher than the first. The result is that the lowest tiers now face a higher price

[111] Berg et al. (2016).
[112] California Public Utilities Code, section 739.
[113] St. John (2015).
[114] CPUC (2015b).

than before, while the higher tiers face a lower one — in other words, a flatter rate structure. This reduces what was formerly a very significant incentive for efficiency and distributed generation deployment for customers using large amounts of electricity. On the other hand, it raises this incentive for customers with lower usage.

Time of use rates are currently optional for residential customers. The CPUC has ordered the IOUs to transition most residential customers to default time of use pricing in 2019.[115] Most commercial and industrial IOU customers in California already face seasonally differentiated default time of use prices, which were introduced in 2014. While these customers can opt into non-time-differentiated rates, few have done so.

Service Quality

California's regulatory system for service quality is more reactive than proactive and has featured several investigations to assess utilities' service quality performance. An early investigation focused on whether PG&E had adequately responded to severe storms in 1995. In its decision, the CPUC ordered standardized service quality and reliability reporting requirements to be developed. Southern California Edison and Sempra had service quality PIMs in rate plans with index-based ARMs during the late 1990s and early 2000s.

Edison's service quality PIMs included one for customer satisfaction, as measured by a survey. In 2003 a whistleblower brought to the utility's attention that fraud had occurred in the customer satisfaction surveys. The company investigated the claims, confirmed that there had been misconduct, expanded the investigation to include the other PIMs, and notified the CPUC.

The Commission opened its own investigation on the matter. It found that Southern California Edison had provided false and misleading data in support of its performance claims on the customer satisfaction survey and health and safety PIMs. The Commission's decision required a refund of rewards that Edison had obtained through false reporting, made the utility forego recovery of additional rewards through these PIMs, and fined the utility an additional sum. The Commission was particularly concerned that the utility had gamed an incentive mechanism, stating that:

> Incentive mechanisms, such as the [PIMs], require a great deal of trust between the Commission and the utility's entire management. In turn, the utility's management must communicate through its practices, rules, and corporate culture that the data submitted to the Commission that impacts the incentive mechanisms must be completely accurate and timely. Increasingly, this Commission is turning to incentive mechanisms in order to align the interests of ratepayers and shareholders and to achieve desirable policy outcomes in the most cost effective and least burdensome manner. If the Commission is to continue to rely on and potentially create new incentive mechanisms, we must be able to trust the utilities to be accurate, timely, and completely honest about their reporting, and further, we must be vigilant against abuse and appropriately penalize violations in order to safeguard the integrity of incentive mechanisms going forward for all utilities.[116]

[115] Ibid.
[116] CPUC (2008), p. 102–103.

6.3 New York

New York has also had a long history with MRPs for energy utilities. Plans have been widely used there since the mid-1990s. Experience with MRPs has spanned some years when electric utilities were still vertically integrated, and more than 15 years after industry restructuring was completed. DSM programs are provided primarily by a state agency, the New York State Energy Research and Development Authority, but utilities also have some programs. MRPs are usually outcomes of negotiated settlements in regulatory proceedings.

The inclination of New York's Public Service Commission and Department of Public Service (DPS) to adopt MRPs has several root causes. Regulatory cost savings can be sizable, since New York's economy is large and there are six investor-owned electric utilities (and even more investor-owned gas utilities) to regulate.[117] MRPs also have been facilitated by New York's long-standing use of forward test years in rate cases. One of the earliest MRPs, for Orange & Rockland Utilities, was motivated in part by concerns about performance incentives. The Commission stated in approving the plan:

> Economic regulation, like most acts of market intervention, can have unintended and undesirable consequences. In the case of a regulated monopoly, the consequence most frequently watched for and least easily avoided is operating inefficiency within the firm, resulting from the "cost plus" nature of price controls. In theory, the [MRP] should encourage greater operating efficiency, because the period of regulatory lag during which the company would be allowed to retain savings from productivity gains would be longer.[118]

Reducing regulatory cost has also been cited in the Commission's support of MRPs. For example, in a 2008 rate case decision for Consolidated Edison, the Commission discussed the drawbacks of annual rate cases.

> We generally prefer multi-year rate plans in instances where the terms are broadly seen to be better than those that might result from a litigated one-year rate case. In addition, we note that this proceeding includes many of the same, or similar, issues and major cost drivers as did the Company's last one-year electric rate case. These circumstances raise a significant concern that the public benefit might not be optimized if the upcoming Consolidated Edison electric rate filing — the third in three years — ultimately boils down to consideration of the same, or similar, issues on which parties largely just replicate arguments we have already carefully reviewed and either accepted or rejected. We also question how well the public interest may be served by the demands on time and resources of the Company, DPS Staff, and other parties in the face of continual annual rate proceedings.[119]

The relatively poor performance of several New York utilities after a series of storms including Superstorm Sandy led the governor to issue an order establishing a commission, called the Moreland Commission on Utility Storm Preparation and Response (Moreland Commission), to investigate and review the storm preparedness of New York's electric utilities, the adequacy of regulatory oversight, and the jurisdiction, responsibility, and mission of New York's energy agency and authority functions.[120] The findings of the Moreland Commission encouraged the governor to push for a reassessment of electric utility regulation more generally. We discuss some Moreland Commission findings further below.

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[117] A seventh investor-owned electric utility, Long Island Lighting, was transferred to the state-owned Long Island Power Authority during the 1990s.
[118] New York Public Service Commission (1990).
[119] New York Public Service Commission (2009), p. 282.
[120] Moreland Commission (2013a).

In 2014 New York's Public Service Commission initiated a generic proceeding to consider how the regulatory system of power distributors and their marketplace roles should evolve in an era of rapid change in distribution, metering, and DER costs and technologies.[121] This came to be called the "REV" proceeding after a Department of Public Service Staff report entitled *Reforming the Energy Vision*.

Track One of the proceeding considered appropriate roles of power distributors going forward. Utilities are envisioned as distributed system platform providers that accommodate customer-side DERs and energy service companies and may offer new services that use smart grid technologies. Utilities are now required to file Distribution System Integration Plans that among other things, consider the use of DERs to avoid capex. The first filings were made last summer.[122] Track Two of the proceeding has addressed miscellaneous ratemaking issues such as rate designs and MRP design. We discuss the outcomes further below.

Plan Designs

New York rate plans have featured forecasted ARMs.[123] Since decoupling has been common, most ARMs have effectively been revenue caps.[124] A "one-way" net plant reconciliation ("claw back") mechanism has been added to MRPs in recent years which returns to customers benefits of capex underspends.[125] Plans typically have a term of only three years. In the early 1990s and since 2007, plans also typically have included revenue decoupling and PIMs for utility DSM. Where New York utilities do not have an approved MRP but have revenue decoupling, they often have filed frequent rate cases. MRPs also typically have featured asymmetrical ESMs that share only surplus earnings.

Service quality PIMs are common in New York and are sometimes extensive. There are PIMs for customer service as well as reliability. In addition to these PIMs, service quality standards for SAIDI and CAIDI have been in place since 1991 which, if breached, require a corrective action plan to be filed with the Commission. Consolidated Edison's most recent plan had separate PIMs for its radial and network systems. This plan also featured PIMs for performance following major events (e.g., outages) and a wide variety of asset management activities.

New York plans during the late 1990s and early 2000s were somewhat different from plans that were approved in the early 1990s and after 2007. These plans did not feature revenue decoupling or DSM PIMs, but retained ESMs and service quality PIMs. Several plans featured rate freezes often tied to restructuring plans or merger approvals. A plan for Niagara Mohawk had a 10-year term.

The Commission issued an order on Track Two of its REV proceeding in 2016, including the design of its regulatory system.[126] Among the specific issues addressed are the following:

- The net plant reconciliation mechanism will be reformed to enable utilities to profit from DERs that displace previously approved capital projects. Because this will often be achieved through increased operating expenses, rather than capital expenses, the existing mechanism would require utilities to forfeit approved capital earnings. This creates a disincentive for utilities to adopt lower cost DER alternatives. To address this, the Commission will permit utilities to retain earnings on previously approved, traditional utility capital projects included

[121] New York Public Service Commission (2014a).
[122] Walton (2016a).
[123] Indexed ARMs have, however, been proposed by utilities on several occasions.
[124] From the late 1990s to mid-2000s, revenue decoupling was not featured in New York regulation. These plans were price caps where base rates were specified for each year of the plan.
[125] An underspend occurs if utility capex is less than the budget which the ARM provides.
[126] New York Public Service Commission (2016a).

in base revenue, even if these projects do not materialize, until rates are reset in the next rate case. To qualify for this treatment, a utility must demonstrate that DSM or other types of DERs displaced the capital project. The Commission expressed interest in considering further modifications to the claw back mechanism in the future, such as sharing any realized savings between the utility and customers over a longer time horizon.

- As utilities transition to a platform provider role, the Commission expects a growing share of their income to be Platform Service Revenues,[127] new revenues arising from the operation or facilitation of distribution-level markets.

- *Earnings Adjustment Mechanisms* are New York's term for performance incentive mechanisms. They are to focus on outcomes, rather than on utility inputs or the attainment of specific program targets, and are not restricted to items under the utility's direct control. The Commission expects these adjustment mechanisms to be most important in the near term, serving as a "bridge" to the time when markets provide utilities with a sizable share of revenue in the form of platform services revenues.

  To avoid encouraging utilities to grow rate base, the Commission stated that Earnings Adjustment Mechanisms should not take the form of basis-point adjustments to earnings (though they may be designed in reference to basis-point changes and fixed in dollar amounts before the mechanisms take effect). Mechanisms also generally should avoid estimated counterfactuals in order to reduce controversy and cost. In addition, they should be financially meaningful, encourage strategic, portfolio-level approaches beyond narrow programs, and generally be structured on a multiyear basis.

  Though specific metrics and associated Earnings Adjustment Mechanisms will be worked out in future proceedings, the Commission provided requirements and guidance in several areas:

  - *System Efficiency.* The Commission will require utilities to propose system efficiency Earnings Adjustment Mechanisms that address both peak reduction and load factor. Initial proposals should include only the possibility of positive adjustments.

  - *Energy Efficiency.* Pending recommendations from the Clean Energy Advisory Council based on State Energy Plan and Clean Energy Standard goals, energy efficiency Earnings Adjustment Mechanisms will be redesigned. One focal point will be systemwide electric usage intensity (e.g., measured as kWh per capita, kWh per customer or kWh per unit of GDP).

  - *Interconnection.* An Earnings Adjustment Mechanism will address interconnection of distributed generation and storage projects over 50 kW. It will include a threshold tied to meeting timeliness requirements, and a positive adjustment based on evaluations by interconnection customers of application quality and applicant satisfaction. Negative adjustments may also be considered in individual utility proceedings. The Track Two order required the utilities to develop an Earnings Adjustment Mechanism for distributed generation connection timeliness, customer satisfaction with distributed generation interconnection processes and audits of failed distributed generation interconnection applications.

[127] One potential problem with Platform Service Revenues is that margins from them are netted off of the revenue requirement in each rate case. Another is that competitors will endeavor to limit the role of utilities in the provision of new services. MRPs can help utilities retain margins from these new revenues for several years.

- *Customer Engagement.* The Commission declined to implement an Earnings Adjustment Mechanism related to general customer engagement. However, the Commission will consider proposals in this area. For example, Earnings Adjustment Mechanisms could reward utilities for increased customer participation in time-varying rates or adoption of ground-source heat pumps and electric vehicles.

- *Scorecards.* The Commission plans to use scorecard metrics to track utility progress, which could serve as the basis for Earnings Adjustment Mechanisms in the future.

- Utilities may also earn new revenues from displacing traditional infrastructure projects with non-wires alternatives (NWAs) in other ways. The Brooklyn Queens Demand Management program of Consolidated Edison (Con Ed) is the best-known example.[128] Approved by the Commission in 2014, its goal is to use DERs to delay or offset the need for traditional infrastructure upgrades in a portion of the Brooklyn and Queens boroughs.[129] In the absence of this program, upgrades needed by 2017 would have an estimated cost of approximately $1 billion and included a new area substation, a new switching station at an existing station, and new subtransmission feeders.[130]

  To overcome the disincentive for Con Ed to pursue NWA projects, the Commission adopted the following performance incentives contingent on satisfactory performance on the company's existing reliability PIMs:[131]

  1. Con Ed is permitted to earn its authorized overall rate of return (as approved in its most recent electric rate case) on all deferred Brooklyn-Queens program costs up to a cap. These amounts would be recovered over a 10-year period.

  2. The utility can earn up to an additional 100 basis points (incremental to its authorized rate of return on equity) on program costs contingent on performance.

  An NWA incentive mechanism was approved in 2016 which gives Central Hudson Gas and Electric a 30 percent share of savings associated with delaying investments in traditional power plant structures and reductions in wholesale capacity requirements. Program costs will be amortized and recovered over the subsequent five-year period.[132]

- The Commission declined to extend the terms of MRPs from three to five years in recognition of the need for a high level of regulatory oversight during the early REV transitional period. However, the Commission stated that longer plans had significant potential to achieve long-term benefits and declined to preclude parties from pursuing longer plans if desired.

Consolidated Edison was the first utility to have its rate case litigated after the Track Two decision was issued. This placed the company in the position of being the first to implement several REV features.[133] A separate decision on the same day as the rate case decision approved an incentive mechanism that allowed

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[128] For further discussion, see Walton (2016b).
[129] New York Public Service Commission (2014b).
[130] Concurrently with the BQDM program, Con Ed is undertaking about 17 MW of traditional infrastructure investments.
[131] The utility proposed an additional shareholder incentive in its application. This proposal was a shared savings mechanism, under which the utility would have retained a 50 percent share of the annual net savings realized by customers. The Commission rejected this proposal, however, believing that the other two incentive mechanisms were sufficient.
[132] New York Public Service Commission (2016b).
[133] In the case of New York State Electric & Gas and Rochester Gas & Electric, Earnings Adjustment Mechanisms are being developed as a compliance filing to the rate case.

Con Ed to receive 30 percent of the net benefits of NWA projects, except on the Brooklyn Queens Demand Management program.[134] Costs of NWA projects will be recovered over a 10-year period. The net plant reconciliation mechanism was revised to allow Con Ed to use the revenue requirements that would otherwise be refunded to customers as a result of capex underspends from successful DER deployments to offset the revenue requirements of any related non-wires alternative project first.

Earnings adjustment mechanisms and metrics were approved to encourage superior Consolidated Edison performance in several areas.

- In the area of energy efficiency and demand response, two metrics are relied on to assess Con Ed's performance. The first encourages Con Ed to increase its incremental gigawatt-hour (GWh) savings from energy efficiency programs. The second metric encourages Con Ed to improve its demand response effectiveness as measured by incremental system peak megawatt (MW) reductions from energy efficiency programs.

- With respect to deployment of incremental DERs, a metric encourages incremental use of DERs from solar energy, combined heat and power, battery storage, demand response and beneficial electrification, such as thermal storage, heat pumps and electric vehicle charging.

- Measurement of customer load factors is intended to encourage Con Ed to improve those of poor load factor customers. This metric is customer-specific and compares the customer's average load to their peak. Due to the need to conduct further research on this metric, no targets or incentives were assigned to this metric for the first year.

- Metrics also measure Con Ed's weather-normalized average use adjusted for incremental beneficial usage. One measures residential use per customer; another measures commercial use per employed person in Con Ed's service territory.

- Separate metrics are used to assess Con Ed's performance on distributed generation interconnection timeliness, customer satisfaction with distributed generation interconnections, and independent audits of failed distributed generation interconnection applications. Development of specific targets was deferred beyond the rate case, so that no Earnings Adjustment Mechanism will apply for the first rate year.

All of the proposed Earnings Adjustment Mechanisms will be reviewed each year for potential revisions. The incentives increase for each Earnings Adjustment Mechanism during the term of the MRP, with the maximum reward exceeding $50 million in year three of the plan.

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[134] New York Public Service Commission (2017).

Outcomes

Utility Cost

Table 6 and Figure 8 compare the power distributor productivity trends of New York electric utilities to the averages for our full U.S. electric utility sample. From 1980–1993, before MRPs became commonplace, the MFP growth of New York power distributors averaged 0.98 percent annually. This was 51 basis points above the average for sampled power distributors nationally. Over the 1994–2014 period during which MRPs have been prevalent, the MFP trend of the New York utilities averaged 0.54 percent annually, whereas the average for our full national sample was a similar 0.45 percent. Capital productivity growth was more rapid in New York but O&M productivity growth was slower. Evidence that MRPs have improved cost performance is therefore not strong. This is not surprising since New York's approach to MRP design is conservative, with short rate case cycles.

Table 6. How the Power Distributor MFP Growth of New York Utilities Compared to That of Other U.S. Electric Utilities: 1980–2014*

	New York Average			U.S. Sample Average		
	MFP	**O&M PFP**	**Capital PFP**	**MFP**	**O&M PFP**	**Capital PFP**
1980	0.78%	-1.47%	1.42%	-0.49%	-4.19%	1.24%
1981	1.57%	1.73%	1.42%	0.17%	-2.42%	1.25%
1982	-0.28%	-4.42%	1.63%	0.87%	-1.20%	1.53%
1983	1.75%	1.82%	1.65%	0.51%	-0.38%	0.98%
1984	2.28%	1.81%	2.37%	1.27%	-0.22%	1.79%
1985	1.74%	-0.19%	2.39%	0.95%	-0.21%	1.37%
1986	1.89%	2.03%	1.82%	0.91%	0.88%	0.97%
1987	0.84%	-1.83%	1.78%	0.44%	-0.12%	0.68%
1988	1.94%	2.09%	1.87%	0.57%	1.55%	0.24%
1989	1.29%	1.73%	0.98%	0.26%	0.00%	0.23%
1990	0.01%	-1.19%	0.56%	0.18%	0.64%	-0.05%
1991	-1.65%	-4.97%	-0.12%	-0.03%	0.58%	-0.32%
1992	1.38%	4.27%	0.18%	0.48%	1.61%	0.10%
1993	0.16%	-0.35%	0.35%	0.45%	1.19%	0.12%
1994	1.67%	4.18%	0.61%	0.94%	2.44%	0.29%
1995	0.65%	0.12%	0.82%	0.94%	3.58%	-0.04%
1996	0.29%	-0.54%	0.59%	0.11%	0.67%	-0.13%
1997	0.16%	-1.63%	0.96%	1.53%	4.68%	0.39%
1998	-0.29%	-5.04%	1.70%	0.67%	0.73%	0.71%
1999	1.70%	1.78%	1.45%	1.08%	2.24%	0.52%
2000	0.60%	1.22%	0.18%	0.89%	0.86%	0.73%
2001	2.23%	2.96%	1.91%	1.20%	2.73%	0.61%
2002	-0.33%	-5.18%	1.18%	0.79%	2.73%	0.33%
2003	1.51%	1.37%	1.66%	-0.03%	-1.50%	0.43%
2004	0.90%	3.65%	-0.53%	0.41%	0.76%	0.22%
2005	-1.50%	-1.35%	-1.46%	-0.07%	-0.25%	0.09%
2006	-1.08%	-2.58%	-0.01%	-0.52%	-1.07%	-0.21%
2007	2.10%	3.91%	0.47%	-0.12%	0.00%	-0.02%
2008	-0.16%	-0.54%	0.58%	-0.99%	-2.06%	-0.09%
2009	2.26%	3.65%	0.32%	1.01%	2.73%	-0.46%
2010	-1.32%	-3.61%	0.90%	-0.27%	-0.47%	0.05%
2011	3.79%	7.39%	0.72%	0.50%	0.05%	0.50%
2012	1.19%	0.67%	0.53%	1.29%	2.90%	0.58%
2013	-2.93%	-6.18%	-0.14%	0.03%	0.40%	-0.05%
2014	-0.09%	-1.02%	0.51%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.72%**	**0.12%**	**0.89%**	**0.45%**	**0.53%**	**0.43%**
1980-1993	**0.98%**	**0.08%**	**1.31%**	**0.47%**	**-0.16%**	**0.72%**
1994-2014	**0.54%**	**0.15%**	**0.62%**	**0.45%**	**0.99%**	**0.24%**
2008-2014	**0.39%**	**0.05%**	**0.49%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs for a majority of New York's electric utilities were in effect.

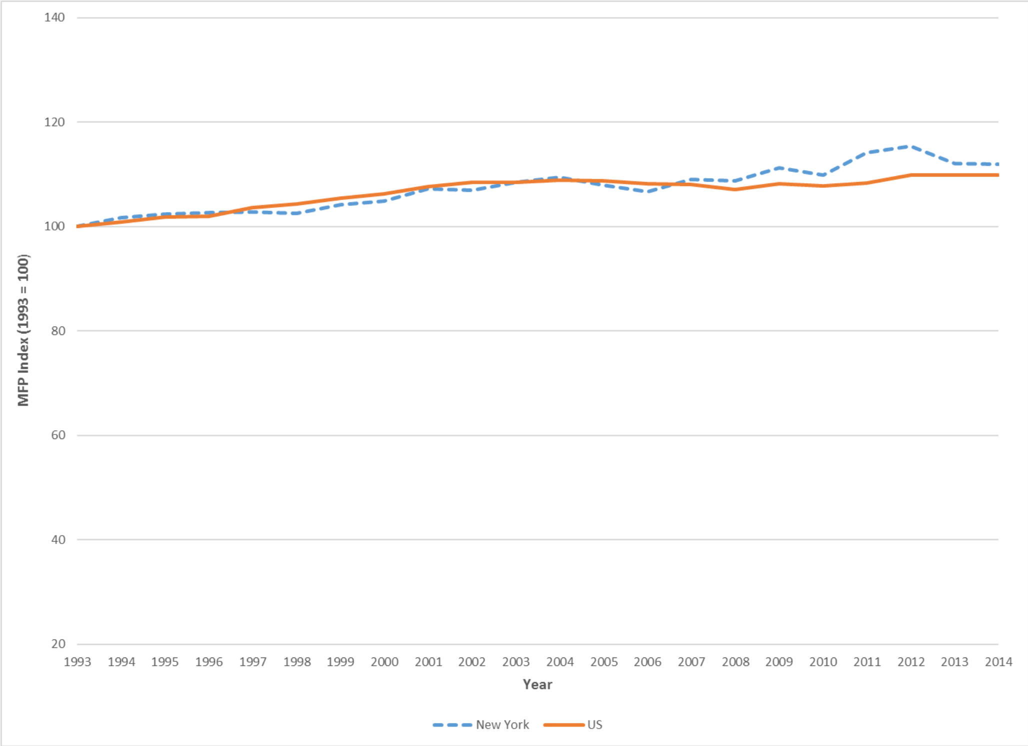

Figure 8. Comparison of Multifactor Productivity Trends of New York Distributors and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of New York distributors has modestly exceeded industry norm under MRPs.

Rate Designs

In recent years New York utilities have had some of the highest residential customer charges in the United States. AMI is not pervasive.[135] The Commission recently directed utilities to develop strategies to increase opt-in of mass market (i.e., residential and small commercial) customers to time-of-use rates.[136] Utilities are to develop promotional and customer engagement tools with reference to best practices in states where participation in opt-in time-varying pricing programs is higher.

Utilities also will offer Smart Home Rates as demonstration projects. These rates will combine granular time-varying rates with location and time-based compensation for DERs, in a way that is managed automatically to optimize value for both the customer and system. Smart Home rates are intended to allow a customer to be compensated for multiple services (e.g., load shifting, peak reduction, voltage regulation).

In the longer term, the Commission supports time-sensitive rates for both commodity and delivery services. It has directed its staff to propose a study of the potential bill impacts of a range of mass-market rate reforms, including time-of-use and demand charges. The Commission identifies Smart Home Rates as “the model for a rate design that should become the widely-adopted norm as markets mature.”[137]

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[135] At least one utility, Consolidated Edison, is beginning a large-scale deployment of AMI.
[136] New York Public Service Commission (2016a).
[137] New York Public Service Commission (2016a), p. 135.

Service Quality

New York's customer service and reliability PIMs generally have been successful. Over the past five years, New York utilities have generally had stable outage frequency and duration (with major storms excluded). In a 2016 staff report analyzing the customer service PIMs, staff concluded:

> With one exception…the electric and gas utilities' performance on measures of customer service quality in 2015 was satisfactory. The [customer service PIMs] currently in place at the utilities in New York State establish strong standards for performance and put significant amounts of shareholder earnings at risk for nonperformance. Overall, these mechanisms have been effective in encouraging companies to make customer service a corporate priority and providing criteria for ensuring that the quality of customer service remains at satisfactory levels.[138]

In spite of these successes there have been some concerns about the utilities' reliability performance. For example, Consolidated Edison was the subject of a 2006–2007 investigation about reliability due in part to complaints by the legislature. Superstorm Sandy had impacts that were particularly severe, leading the Moreland Commission to conclude in its final report that the utilities had not done enough to effectively respond to severe storms.[139]

6.4 MidAmerican Energy

MidAmerican Energy is a VIEU based in Des Moines that provides electric service in most of Iowa and portions of two adjacent states. The company operated under a sequence of MRPs without intervening rate cases for more than a decade through a series of settlements approved by the Iowa Utilities Board. The settlements had many common features, including rate freezes that extended to charges for energy procured.

Plan Designs

MidAmerican's first MRP began with a 1997 general rate case settlement that featured a three-and-a-half-year rate case stayout.[140] Residential rates were reduced in two steps at the outset. Rates for commercial and industrial customers were not directly reduced. Instead, amounts allocated for these reductions were to be used to fund negotiated contracts with customers or unbundled pricing retail access pilots. The energy adjustment clause was eliminated, exposing the company to fluctuations in prices of energy commodities but permitting it to benefit if high prices in bulk power markets bolstered margins from sales in these markets. A capital cost tracker was included in the plan to address costs of plant additions at the Cooper Nuclear Station. An earnings sharing mechanism (ESM) refunded a share of any earnings surpluses to customers.[141] An off-ramp was included to allow rate cases in the event that earnings were excessively low or high. Iowa law required utilities to offer DSM programs. Costs of these programs were tracked, but no DSM PIMs were approved. Service quality monitoring was instituted in the early 2000s through a change to the state's administrative code.

This plan also allowed MidAmerican to utilize additional marketing flexibility through waivers of existing flexible pricing rules. The company could provide discounts based on the cost to serve individual customers without being required to offer the same discount to all competing customers. The pricing floor

[138] New York State Department of Public Service (2016), pp. 13–14.
[139] Moreland Commission (2013b).
[140] Iowa Utilities Board (1997).
[141] The term revenue sharing is often used instead of earnings sharing in Iowa.

was set at the short-run marginal cost of serving that customer. Contracts in excess of five years were permitted.

Subsequently, approved settlements made small changes to the framework but continued the rate case stayout.[142] The customers' share from the earnings sharing mechanism was redirected into a source of funding for new plants. The capital tracker for Cooper plant additions expired.

Through separate legislation, Iowa electric utilities, including MidAmerican, gained unusual certainty with regard to future ratemaking treatment of generating plant additions. Instead of cost trackers, this certainty has been in the form of ratemaking principles to be applied to new facilities when they are added to the utility's rate base. These principles may include a prudence decision up to a cost cap, the allocation of plant costs to Iowa ratepayers, allowed ROE for the life of the plant, and plant service life.

Throughout the 1997–2013 period, MidAmerican's tariffed base rates did not increase. For residential customers, they decreased by $15 million. The company was nevertheless able to handle effects of several severe weather events and environmental compliance while building a coal-fired generating unit, a gas-fired combined cycle plant, and more than 1,800 MW of wind generation. These assets were added to the utility's rate base years after they entered service, which allowed them to be added at less than their gross plant value due to depreciation. The customer share of earnings yielded by the ESM-funded accelerated depreciation of the coal-fired Walter Scott, Jr. Energy Center Unit 4 exceeded $300 million.[143]

Surplus earnings were aided by bulk power market sales margins. In 2003 testimony, a MidAmerican witness stated:

> In Iowa rate cases prior to the adoption of revenue sharing in 1997, the appropriate treatment of wholesale margins was a contested issue. Since the adoption of revenue sharing, these margins have been shared with retail customers. In fact, since revenues from Iowa retail operations have consistently produced returns below 12% [the threshold for revenue sharing], the revenue sharing mechanism has essentially been a mechanism for sharing these wholesale margins with retail customers.[144]

Declines in bulk power market prices after 2007 helped trigger an off-ramp that resulted in a cost tracker being added to the plan. Other stresses identified by the company in requesting a tracker included environmental, coal and coal transportation costs. The company filed a full rate case in 2013, resulting in a new MRP that phased in a $135 million base rate increase over three years. This MRP also reinstituted an energy adjustment clause. Variances from test year revenue levels resulting from sales for resale continue to be shared solely through the ESM.

Outcomes

Cost Performance

The infrequency of rate cases and the unlikely ability of poorly managed distributor costs to trigger rate cases gave MidAmerican incentive to contain distributor costs that approached those in competitive markets. Table 7 and Figure 9 compare the power distributor productivity growth of MidAmerican to averages for our full U.S. electric utility sample. From 1980 to 1995, before the start of MRPs,

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[142] Iowa Utilities Board (2001; 2003).
[143] Fehrman (2012), p. 3.
[144] Gale (2003), pp. 24–25.

MidAmerican's power distributor MFP growth fell by 1.37 percent annually. This was 190 basis points below the MFP growth trend of sampled power distributors nationally. Over the 17-year period over which MidAmerican Energy operated without a rate case (1997–2013), the MFP of its power distributor services averaged 1.16 percent annual growth. That compares to the 0.42 percent trend for our full sample of U.S. power distributors during the same period. The MFP growth differential therefore averaged 74 basis points in the years of the MRPs. The capital productivity growth of MidAmerican was especially rapid.

Service Quality

In 2015, staff of the Iowa Utilities Board performed a review of reliability performance of the state's two large investor-owned electric utilities. It found that between 2002 and 2014, reliability metrics for both companies were stable. This report also showed that MidAmerican's budgeted transmission and distribution expenses had risen between 2002 and 2005, plateaued until 2008, and fell off for 2009, 2010 and 2011, coinciding with dropping bulk power prices.

DSM Programs

In the eight years for which data were available since 2006, Iowa has averaged a 10.25 average ranking (out of 50) in ACEEE's scorecard on the percent of electric revenues devoted to energy efficiency spending.

Table 7. How the Power Distributor MFP Growth of MidAmerican Energy Compared to That of Other U.S. Electric Utilities: 1980–2014*

Year	MidAmerican Energy			U.S. Sample Average		
	MFP	O&M PFP	Capital PFP	MFP	O&M PFP	Capital PFP
1980	-1.93%	-4.26%	-0.78%	-0.49%	-4.19%	1.24%
1981	-2.73%	-5.09%	-1.58%	0.17%	-2.42%	1.25%
1982	-0.58%	3.85%	-2.54%	0.87%	-1.20%	1.53%
1983	1.20%	0.45%	1.46%	0.51%	-0.38%	0.98%
1984	1.89%	1.51%	2.00%	1.27%	-0.22%	1.79%
1985	-0.91%	2.81%	-1.80%	0.95%	-0.21%	1.37%
1986	-0.31%	-2.19%	0.11%	0.91%	0.88%	0.97%
1987	-3.56%	-4.46%	-3.35%	0.44%	-0.12%	0.68%
1988	-1.58%	-1.40%	-1.63%	0.57%	1.55%	0.24%
1989	-2.83%	-5.80%	-1.94%	0.26%	0.00%	0.23%
1990	-1.73%	-1.63%	-1.76%	0.18%	0.64%	-0.05%
1991	-1.82%	0.89%	-2.71%	-0.03%	0.58%	-0.32%
1992	-2.57%	1.99%	-3.92%	0.48%	1.61%	0.10%
1993	-0.02%	2.36%	-0.70%	0.45%	1.19%	0.12%
1994	-0.03%	1.26%	-0.40%	0.94%	2.44%	0.29%
1995	-4.42%	2.64%	-6.55%	0.94%	3.58%	-0.04%
1996	-0.19%	2.55%	-0.99%	0.11%	0.67%	-0.13%
1997	-0.06%	-3.21%	0.84%	1.53%	4.68%	0.39%
1998	-0.44%	-6.77%	1.45%	0.67%	0.73%	0.71%
1999	1.20%	3.47%	0.54%	1.08%	2.24%	0.52%
2000	1.97%	-1.61%	3.04%	0.89%	0.86%	0.73%
2001	-0.02%	-3.98%	1.30%	1.20%	2.73%	0.61%
2002	1.15%	3.17%	0.43%	0.79%	2.73%	0.33%
2003	0.48%	-1.19%	1.10%	-0.03%	-1.50%	0.43%
2004	1.15%	-1.15%	2.13%	0.41%	0.76%	0.22%
2005	0.58%	-0.01%	0.88%	-0.07%	-0.25%	0.09%
2006	1.27%	2.15%	0.72%	-0.52%	-1.07%	-0.21%
2007	-0.42%	-3.61%	2.59%	-0.12%	0.00%	-0.02%
2008	0.85%	1.50%	-0.27%	-0.99%	-2.06%	-0.09%
2009	6.10%	9.84%	0.58%	1.01%	2.73%	-0.46%
2010	2.00%	1.35%	2.48%	-0.27%	-0.47%	0.05%
2011	1.99%	3.30%	1.21%	0.50%	0.05%	0.50%
2012	2.54%	3.77%	1.87%	1.29%	2.90%	0.58%
2013	0.75%	-2.73%	2.42%	0.03%	0.40%	-0.05%
2014	2.32%	1.20%	2.85%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.04%**	**0.03%**	**-0.03%**	**0.45%**	**0.53%**	**0.43%**
1980-1995	**-1.37%**	**-0.44%**	**-1.63%**	**0.53%**	**0.23%**	**0.65%**
1997-2013	**1.16%**	**0.38%**	**1.24%**	**0.42%**	**0.90%**	**0.23%**
2008-2014	**2.37%**	**2.61%**	**1.59%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs were in effect.

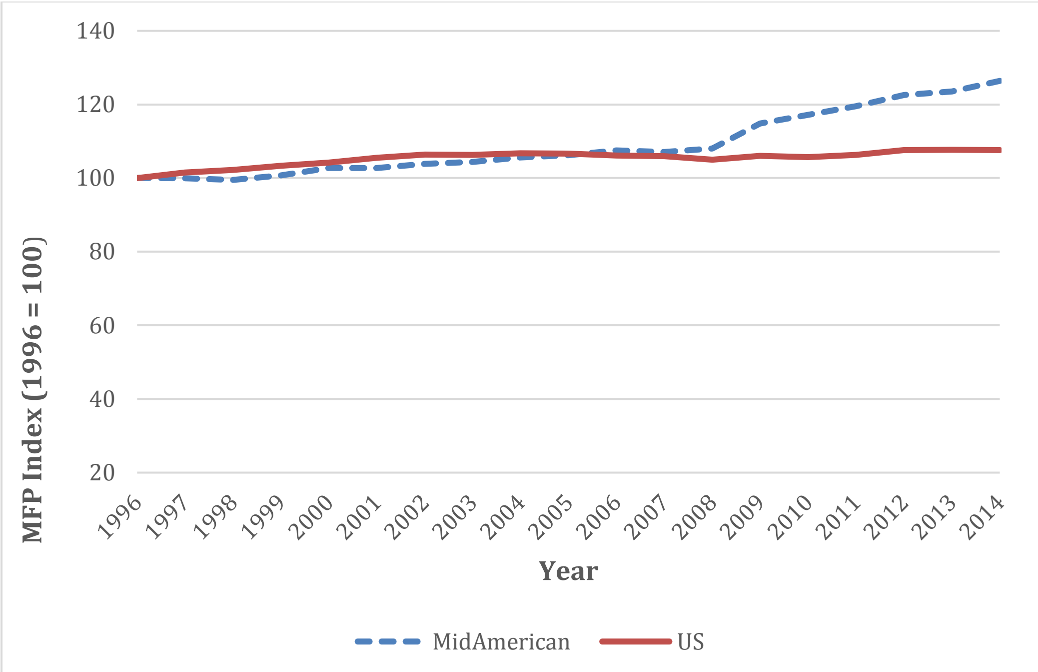

Figure 9. Comparison of Multifactor Productivity Trends of MidAmerican Energy and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of MidAmerican exceeded the industry norm under its MRPs.

6.5 Other U.S. Electric Utilities With Extended Rate Stayouts

We noted above that many U.S. electric utilities have avoided general rate cases for lengthy periods. These utilities have been able to operate without rate cases for various reasons. In some cases, utility costs were likely to grow slowly due, for example, to recent completion of one or more large generating stations. Some utilities were able to slow cost growth with mergers or acquisitions. Others may have started their stayout periods with favorable initial rates due to high allowed rates of return. Some operated under an MRP for part of the period or a rate freeze during transition to retail power market competition and were not required to file a rate case upon their conclusion.

Table 8 identifies U.S. electric utilities in our sample that have experienced rate stayouts exceeding 12 years since 1980. About half of these utilities were vertically integrated throughout the sample period. Others started as VIEUs but restructured during the period.

We calculated productivity trends of these utilities as power distributors during the years of their rate stayouts and compared these trends to average annual productivity growth rates of our full U.S. sample during the same years. Table 8 presents results. We found that multifactor productivity growth of utilities during extended rate stayouts exceeded that of the full U.S. sample during the same period by 29 basis points on average. Operation and maintenance and capital productivity growth were both superior. During other years of the full 1980–2014 sample period, MFP growth of these utilities exceeded MFP growth of the full U.S. sample by less than a basis point on average. This evidence suggests that extended rate stayouts lowered distributor costs.

Table 8. Difference Between Company and U.S. Power Distributor MFP Trends During Extended Stayout Periods

	Stayout Period			Stayout Period MFP Trend			Stayout Period O&M PFP Trend			Stayout Period Capital PFP Trend		
Company	Start	End	Duration*	Company	US Sample	Difference	Company	US Sample	Difference	Company	US Sample	Difference
Baltimore Gas and Electric Company	1993	2010	18	0.30%	0.45%	-0.15%	1.42%	1.11%	0.31%	-0.02%	0.20%	-0.21%
Dayton Power and Light Company	1992	2014	23	0.49%	0.45%	0.04%	1.76%	1.02%	0.74%	0.07%	0.23%	-0.15%
Duke Energy Carolinas, LLC	1991	2007	17	0.65%	0.51%	0.14%	2.91%	1.29%	1.62%	-0.10%	0.22%	-0.32%
Duke Energy Progress, LLC	1988	2012	25	0.64%	0.45%	0.19%	2.42%	1.09%	1.32%	-0.10%	0.19%	-0.29%
Duquesne Light Company	1988	2006	19	1.04%	0.52%	0.53%	1.61%	1.27%	0.34%	0.96%	0.22%	0.74%
El Paso Electric Company	1995	2009	15	0.76%	0.46%	0.30%	2.58%	1.12%	1.46%	-0.82%	0.20%	-1.02%
Fitchburg Gas and Electric Light Company	1985	1999	15	-0.35%	0.63%	-0.98%	0.10%	1.36%	-1.27%	-0.30%	0.34%	-0.64%
Florida Power & Light Company	1984	2001	18	0.99%	0.71%	0.27%	2.78%	1.32%	1.46%	0.24%	0.46%	-0.22%
Indiana Michigan Power Company	1993	2007	15	0.41%	0.55%	-0.14%	1.41%	1.32%	0.09%	-0.09%	0.27%	-0.36%
Indianapolis Power & Light Company	1995	2014	20	0.97%	0.42%	0.55%	1.38%	0.91%	0.47%	0.85%	0.24%	0.62%
Kentucky Power Company	1991	2005	15	0.41%	0.62%	-0.22%	1.28%	1.54%	-0.25%	-0.06%	0.27%	-0.33%
Kentucky Utilities Company	1983	1999	17	0.61%	0.66%	-0.05%	0.37%	1.17%	-0.80%	0.62%	0.46%	0.16%
Kingsport Power Company	1992	2014	23	0.26%	0.45%	-0.19%	0.70%	1.02%	-0.32%	0.19%	0.23%	-0.04%
Massachusetts Electric Company	1995	2009	15	1.27%	0.46%	0.81%	1.93%	1.12%	0.81%	0.75%	0.20%	0.54%
Metropolitan Edison Company	1993	2006	14	1.61%	0.60%	1.01%	1.88%	1.41%	0.47%	1.51%	0.29%	1.22%
ALLETE (Minnesota Power)	1994	2008	15	1.50%	0.46%	1.04%	1.23%	1.10%	0.13%	1.61%	0.25%	1.35%
MDU Resources Group, Inc.	1987	2001	15	1.13%	0.65%	0.49%	1.07%	1.56%	-0.49%	1.15%	0.27%	0.88%
Niagara Mohawk Power Corporation	1995	2009	15	1.64%	0.46%	1.18%	3.03%	1.12%	1.91%	0.35%	0.20%	0.14%
Nstar Electric	1992	2005	14	0.15%	0.67%	-0.52%	0.92%	1.61%	-0.69%	-0.26%	0.31%	-0.57%
Ohio Edison Company	1990	2007	18	1.23%	0.49%	0.74%	1.24%	1.26%	-0.02%	1.19%	0.21%	0.99%
Ohio Power Company	1995	2011	17	0.46%	0.42%	0.04%	1.43%	0.96%	0.47%	0.13%	0.21%	-0.09%
Otter Tail Corporation	1993	2007	15	0.02%	0.55%	-0.53%	-0.36%	1.32%	-1.68%	0.40%	0.27%	0.14%
PECO Energy Company	1990	2010	21	0.91%	0.41%	0.50%	1.19%	1.09%	0.10%	0.74%	0.16%	0.58%
Pennsylvania Electric Company	1984	2006	23	0.82%	0.58%	0.23%	1.32%	1.07%	0.25%	0.64%	0.39%	0.24%
Pennsylvania Power Company	1988	2014	27	0.62%	0.42%	0.20%	1.31%	0.97%	0.33%	0.35%	0.20%	0.15%
Potomac Edison	1994	2010	17	1.71%	0.45%	1.27%	2.24%	1.11%	1.14%	1.48%	0.20%	1.28%
Tampa Electric Company	1993	2008	16	0.95%	0.46%	0.50%	1.67%	1.11%	0.56%	0.75%	0.25%	0.51%
Duke Energy Kentucky, Inc.	1992	2006	15	0.84%	0.59%	0.25%	2.99%	1.43%	1.56%	0.01%	0.28%	-0.27%
West Penn Power Company	1995	2014	20	1.29%	0.42%	0.86%	2.49%	0.91%	1.58%	0.84%	0.24%	0.60%
Averages												
Stayout Period Average				**0.80%**	**0.52%**	**0.29%**	**1.60%**	**1.20%**	**0.40%**	**0.45%**	**0.26%**	**0.19%**

* Period is inclusive of both endpoints. End dates in January and start dates in December were assigned values one year earlier and later respectively.

6.6 Statistical Tests of Productivity Impacts

The productivity growth rates of individual utilities are quite volatile from year to year. Differences between the annual productivity growth rates of utilities operating under MRPs and annual full sample growth rates may therefore not reflect the impact of the plans. A statistical technique called *hypothesis testing* can be used to infer whether a utility's productivity growth is impacted by an MRP or, if instead, the observed difference between the productivity trends of individual utilities operating under MRPs and the full sample is a coincidence caused by volatility. We conducted hypothesis tests, called *T-tests*, to evaluate whether the average productivity trend of a utility under an MRP or stay out was significantly greater than the productivity trend of the full sample during the same years.

The first T-test was applied to observations of the differences in the MFP trends between utilities operating under a stay out and the full sample during the stay out period. The null hypothesis was that the difference in productivity trends is equal to zero. The alternative hypothesis is that the difference is greater than zero or, on average, utilities operating under a stayout have higher productivity trends than the full U.S. sample during the stayout period. The sample (N=29) consists of the number of "stayout utilities" in Table 8. The mean difference in the productivity trend is .29 percent, and the standard deviation is .53 percent. The t-statistic for this sample is 2.914, which is greater than the 5 percent one-sided critical value of 1.701. Thus, we can reject the null hypothesis in favor of the alternative hypothesis that companies operating under a stayout have a higher productivity trend during the stayout period than the full sample.

A second T-test was applied to observations of the differences between the productivity trends of utilities operating under formal MRPs as well as stayouts and the trend for the full sample in the same years. The null and alternative hypothesizes were the same as in the first test. The sample (N=40) consists of the utilities in the first test plus the California and New York utilities that have operated under an MRP, MidAmerican Energy, and Central Maine Power. The mean difference in the productivity trend is .22 percent and the standard deviation is .61 percent. The t-statistic for this sample is 2.224, which is greater than the 5 percent one-sided critical value of 1.683. Thus, we can again reject the null hypothesis in favor of the alternative hypothesis. The average difference in the productivity trend of .22 percent is half of the productivity trend of the full sample over the 1980–2014 time period, suggesting that MRPs have an economically significant effect on utility operations.

6.7 PBR for Ontario Electric Utilities

The Ontario Energy Board has emerged in recent years as a top practitioner of PBR.[145] The event that drove innovation was the transfer of responsibility to the Board in the late 1990s to regulate more than 200 provincial power distributors. In addition to power distributors, the Board regulates large provincially owned transmission and generation companies and two large gas utilities.

Power distributors regulated by the Board are remarkably varied. Hydro One, which provides most transmission services in Ontario, also provides distribution services to many towns and unincorporated areas. In addition, large distributors serve Ottawa and Toronto. Most other distributors serve small towns, suburbs or rural areas of the province, and some have just a few hundred or thousand customers. Many of these distributors are municipally owned while the largest, Hydro One Networks, is provincially owned.

[145] PEG Research has advised the Board on PBR for many years, performing several productivity and benchmarking studies.

Despite long experience with cost of service regulation (for gas utilities), the Board opted to use MRPs in power distributor regulation.[146] The Board stated in a draft policy decision three reasons why use of PBR would be helpful in electric utility regulation:

1. With passage of [a bill restructuring the electricity industry], the Board will have the task of regulating a large number of diverse utilities in the province. Since PBR has the potential to provide an expedient mechanism for adjusting rates over time as circumstances change, it is expected to result in fewer rate reviews before the Board and, hence, a lesser regulatory burden.

2. PBR would allow the Board to establish minimum service quality and reliability standards and maintain compliance with these standards.

3. PBR can provide greater incentives for cost reduction and productivity gains compared to those available under traditional cost of service regulation while protecting the interests of consumers.[147]

The Board has since approved a sequence of multiyear rate plans. PBR is called *incentive regulation* (IR) and rate plans are called *incentive regulation mechanisms* (IRMs). The first plan (IRM1) began in 2001. The Board extended this plan to March 2005 to allow utilities additional time to "explore the incentives for improvements and savings provided by the current PBR regime." However, IRM1 was suspended well before its termination date as a result of price spikes in Ontario's new bulk power market. Bill 210, enacted in December 2002, froze existing rates until May 2006 unless approval was otherwise granted by the Minister of Energy.[148]

Rates were adjusted in May 2006 based on rate cases filed in 2005. Between 1999 and May 2006, distributors therefore operated without rate cases and received only one or two modest base rate increases. During this period, utilities had strong incentives to contain costs, and some utilities may have deferred some expenditures.

IRM2 used the May 2006 rates as a starting point. Roughly a third of all distributors were then scheduled for rate cases in each year of the 2008–2010 period. After these rate cases (called *rebasings*), distributors switched over to IRM3. Terms of these plans were initially fixed at three years plus a rebasing year. This was later extended, resulting in plans for some companies lasting five years. Extension was partly based on the Board's in-depth reexamination of its ratemaking practices, called "A Renewed Regulatory Framework for Electricity," which began in 2010. A fourth generation IRM and some optional alternative MRP approaches resulted from these deliberations.

Plan Design

Attrition Relief Mechanism

All four IRMs featured indexed price caps. Macroeconomic inflation measures have been used in some plans and industry-specific measures in others. X factors have commonly had two components: a productivity factor reflecting the MFP trend of a peer group and a stretch factor. The peer groups in first and fourth generation IRMs were broad samples of Ontario power distributors, whereas the peer group in the third generation IRM was a broad sample of U.S distributors.

[146] The Board has subsequently embraced MRPs for regulation of provincial gas distributors.
[147] Ontario Energy Board (1998), p. 3.
[148] Legislative Assembly of Ontario (2002).

Stretch factors in third and fourth generation IRMs have varied between utilities based on results of statistical benchmarking studies commissioned by the Board. The benchmarking study in the fourth generation PBR uses an econometric model of total cost and is updated annually. Details of this benchmarking methodology are discussed in Appendix B.3.

Capital Cost Trackers

Capital cost treatments have evolved over Ontario's four IRMs. Supplemental revenue for capex was not available in the first IRM. A separate Ontario policy led to the use of trackers to finance costs of AMI deployment. In the proceeding to approve IRM2, distributors requested supplemental revenue for capex. This request was rejected due to a lack of perceived need, but distributors claiming a need for high capex were permitted to file a rate case early. The Board expressed concerns about special treatments of capital in its decision:

> In a capital intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting, and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.[149]

During the proceeding that led to IRM3, a number of utilities again argued that an indexed price cap would not fund their special capex needs. The Board responded by adding to the plans an Incremental Capital Module that could provide distributors with supplemental capex funding. The Board described this as "reserved for…circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[150] The eligibility criteria for supplemental capex funding subsequently evolved but have consistently required that the capex funded by an Incremental Capital Module not be recoverable in rates, be prudent and the distributors' most cost-effective option, and exceed a materiality threshold. An eligibility formula ensures that forecasted total capex exceeds funding expected from depreciation and higher revenue from price cap index escalation and growth in billing determinants by a certain percentage (currently 10 percent).

Distributors are required to report their actual capex annually. Variances between forecasted and actual capex are reviewed by the Board to determine whether they are material enough to warrant a true-up in a subsequent rate case. Cost overruns are reviewed for prudence, while material underspends result in refunds to ratepayers.

Around 15 of approximately 70 Ontario power distributors have received approval for revenue from Incremental Capital Modules. These modules are typically used to address costs of large capital projects. About two-thirds of applications filed under the program included transformer-related assets as the focal point of the funding request.[151]

In 2014 the Board made "Advanced" Capital Modules rather than Incremental Capital Modules the major source of supplemental capital revenue in IRMs. Utilities must apply in advance, at the time of their rate cases, for supplemental funding of projects that are detailed in five-year Distribution System Plans. Reviews of Advanced Capital Module requests thus coincide with a review of projects proposed in Distribution System Plans, allowing for greater regulatory efficiency. An Incremental Capital Module

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[149] Ontario Energy Board (2006), p. 37.
[150] Ontario Energy Board (2008), p. 31.
[151] Ontario Energy Board (2014), p. 7.

remains available for projects not included in a Distribution System Plan, as well as for projects that are in the plan whose eligibility for supplemental funding could not be determined in the rate case, or projects that expand after the plan is presented.

Other Plan Provisions

Terms of incentive regulation mechanisms in Ontario have varied over the years but have typically been four or five years. Reliability PIMs have never been used in Ontario power distributor regulation. However, reliability metrics and targets have been used routinely since IRM1.

Demand-side management PIMs and LRAMs have been offered as an incentive for distributors' DSM programs. A third-party administrator also offers DSM programs.

An earnings sharing mechanism to address overearnings was established for IRM1 but was abandoned in later plans. Some Custom IR plans include such a mechanism where distributor underspending is a concern.

New Plan Options

The Renewed Regulatory Framework deliberations resulted in two additional options to address the diversity of Ontario distributors.

- Custom IR is designed for distributors expecting several years of high capex. ARMs are based on forecasts of O&M and capital cost. Forecasts should be informed by Board-sponsored productivity and benchmarking analyses. Distributors operating with a Custom IR plan do not have the option to request supplemental capital funding. Custom IR plans have recently been granted to several of the larger distributors.

- The Annual IR index is designed for distributors that do not expect to undertake large capital projects. This option features a price cap index with an inflation — X formula, but the X factor is fixed to reflect the high end of the stretch factor range in IRM4 for all plan years. Utilities that choose the Annual IR index cannot obtain supplemental capital funding. The term of a plan with an Annual IR index is not fixed. The availability to distributors of IRM4 and the Annual IR index is a good example of the use of menus in MRP design.

Scorecards

Part of the implementation of the Renewed Regulatory Framework has been the development of a performance scorecard for Ontario distributors. The scorecard includes data on a distributor's cost, earnings, customer service quality, reliability, DSM and safety performance.

Figure 10 provides an example of a scorecard which was posted on the website of the Board.[152] Cost performance is addressed by two unit cost metrics and the outcome of the econometric benchmarking study that the Board updates annually. Financial metrics include a comparison of the company's ROE to its regulated targets. There are also metrics for less traditional areas, such as peak load management and the quality of service to renewable generation customers.

[152] Scorecard - Hydro Ottawa Limited (2015), http://www.ontarioenergyboard.ca/documents/scorecard/2014/Scorecard%20-%20Hydro%20Ottawa%20Limited.pdf.

Results are presented in a manner that informs the reader of the utility's performance. For example, a company's billing accuracy is presented along with the target. The trend in performance is indicated for several metrics.

Outcomes

<u>Cost Performance</u>

Table 9 and Figure 11 present productivity trends of Ontario power distributors over the 2003–2011 period. This sample period excludes early years of operation under MRPs in Ontario, including the years of the rate freeze. Some distributors in the sample period we consider may have been catching up on their capex after years of deferrals.

Our results differ from those relied upon by the Board to set X factors in IRM4 because we have changed the output index to rely solely on customers, in order to make results more comparable to those from our U.S. productivity research for Berkeley Lab.[153] We have removed

2012 from our calculations due to concerns about cost data for that year.[154] Note also that the sample excludes Ontario's two largest distributors, Hydro One and Toronto Hydro Electric.

The table shows that Ontario distributors' multifactor productivity grew on average by 0.45 percent annually from 2003 to 2011. This exceeded the U.S. trend of -0.01 percent for these years by 4 basis points. O&M productivity averaged 0.76 percent annually while capital productivity growth averaged 0.26 percent annually. The year-by-year results show that O&M, capital and multifactor productivity grew most rapidly during the 2003–2005 period, the last years of the rate freeze. MFP growth then slowed and was negative in two years.

[153] The original results can be found in Kaufmann, Hovde, Kalfayan, and Rebane (2013). Our results were updated using the working papers:
http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Renewed%20Regulatory%20Framework/Measuring%20Performance%20of%20Electricity%20Distributors.

[154] While data for 2012 are available, use of these data is problematic for several reasons. For example, Ontario distributors were in the process of changing accounting systems from Canadian Generally Accepted Accounting Principles to the International Financial Reporting Standards, likely making data less comparable.

Scorecard - Hydro Ottawa Limited 9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%	flat	90.00%	
		Scheduled Appointments Met On Time		100.00%	97.30%	97.40%	97.40%	98.30%	down	90.00%	
		Telephone Calls Answered On Time		82.10%	82.90%	82.50%	82.20%	80.30%	down	65.00%	
	Customer Satisfaction	First Contact Resolution					85.2%	84.1%			
		Billing Accuracy					99.6%	99.61%	flat	98.00%	
		Customer Satisfaction Survey Results					90%	83%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	NI	C	C	C	up		C
		Serious Electrical Incident Index	Number of General Public Incidents	1	0	1	0	1	flat		0
			Rate per 10, 100, 1000 km of line	0.186	0.000	0.178	0.000	0.182	flat		0.076
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		1.05	2.44	1.31	1.64	1.59	up		at least within 1.05 - 2.44
		Average Number of Times that Power to a Customer is Interrupted		0.77	1.40	1.13	1.36	0.86	up		at least within 0.77 - 1.40
	Asset Management	Distribution System Plan Implementation Progress					105%	94%			
	Cost Control	Efficiency Assessment				3	3	3			
		Total Cost per Customer [1]		$536	$529	$569	$579	$623			
		Total Cost per Km of Line [1]		$29,776	$28,793	$31,107	$33,222	$36,169			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			14.13%	28.85%	45.57%	70.53%	target not met		85.26MW
		Net Cumulative Energy Savings (Percent of target achieved)			37.74%	65.64%	88.69%	110.71%	target met		374.73GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.45	1.43	1.18	1.07	0.86			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.22	1.32	1.37	1.64	1.65			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.57%	9.42%	9.42%	9.42%			
			Achieved		7.86%	9.41%	7.80%	8.06%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Legend: up down flat target met target not met

Figure 10. Sample Ontario Performance Metrics Scorecard.

Table 9. Productivity Trends of Ontario Power Distributors: 2003–2011

	Output		Inputs						Productivities					
	Total Customers[1]		Capital[1]		O&M[1]		Multifactor[2]		Capital		O&M		Multifactor	
Year	Level	Growth	Level	Growth	Level	Growth	Level	Growth	Level	Growth	Level	Growth	Level	Growth
		[A]		[B]		[C]		[D]		[E = A-B]		[F = A-C]		[G = A-D]
2002	2,528,664		100		100		100.00		100.00		100.00		100.00	
2003	2,590,817	2.43%	101	1.01%	102	1.77%	101.30	1.29%	101.43	1.42%	100.66	0.66%	101.14	1.13%
2004	2,647,118	2.15%	103	1.66%	100	-1.51%	101.79	0.48%	101.92	0.49%	104.41	3.66%	102.84	1.67%
2005	2,703,821	2.12%	104	1.65%	99	-1.14%	102.42	0.61%	102.40	0.47%	107.87	3.26%	104.40	1.51%
2006	2,748,114	1.62%	105	0.80%	101	1.50%	103.51	1.06%	103.25	0.82%	108.01	0.12%	104.99	0.56%
2007	2,781,589	1.21%	108	2.44%	105	3.82%	106.62	2.96%	101.99	-1.23%	105.22	-2.61%	103.17	-1.75%
2008	2,823,654	1.50%	109	1.16%	106	1.67%	108.08	1.36%	102.34	0.34%	105.04	-0.17%	103.28	0.15%
2009	2,849,054	0.90%	109	0.19%	107	0.44%	108.39	0.29%	103.07	0.70%	105.52	0.45%	103.95	0.61%
2010	2,885,251	1.26%	111	1.80%	104	-2.39%	108.61	0.20%	102.52	-0.54%	109.45	3.65%	105.08	1.06%
2011	2,919,186	1.17%	113	1.30%	108	3.28%	110.87	2.06%	102.38	-0.13%	107.16	-2.11%	104.12	-0.89%
Average Annual Growth Rates:														
2003-2011		**1.60%**		**1.33%**		**0.83%**		**1.15%**		**0.26%**		**0.76%**		**0.45%**

Notes:

[1] Data are from PEG Working Papers: Part II - TFP and BM database calculation, filed with PEG's report "Empirical Research in Support of Incentive Rate-Setting: Final Report to the Ontario Energy Board" on November 21, 2013 (and updated on January 24, 2014).

[2] This is a Törnqvist index using the total cost shares of capital and OM&A as weights.

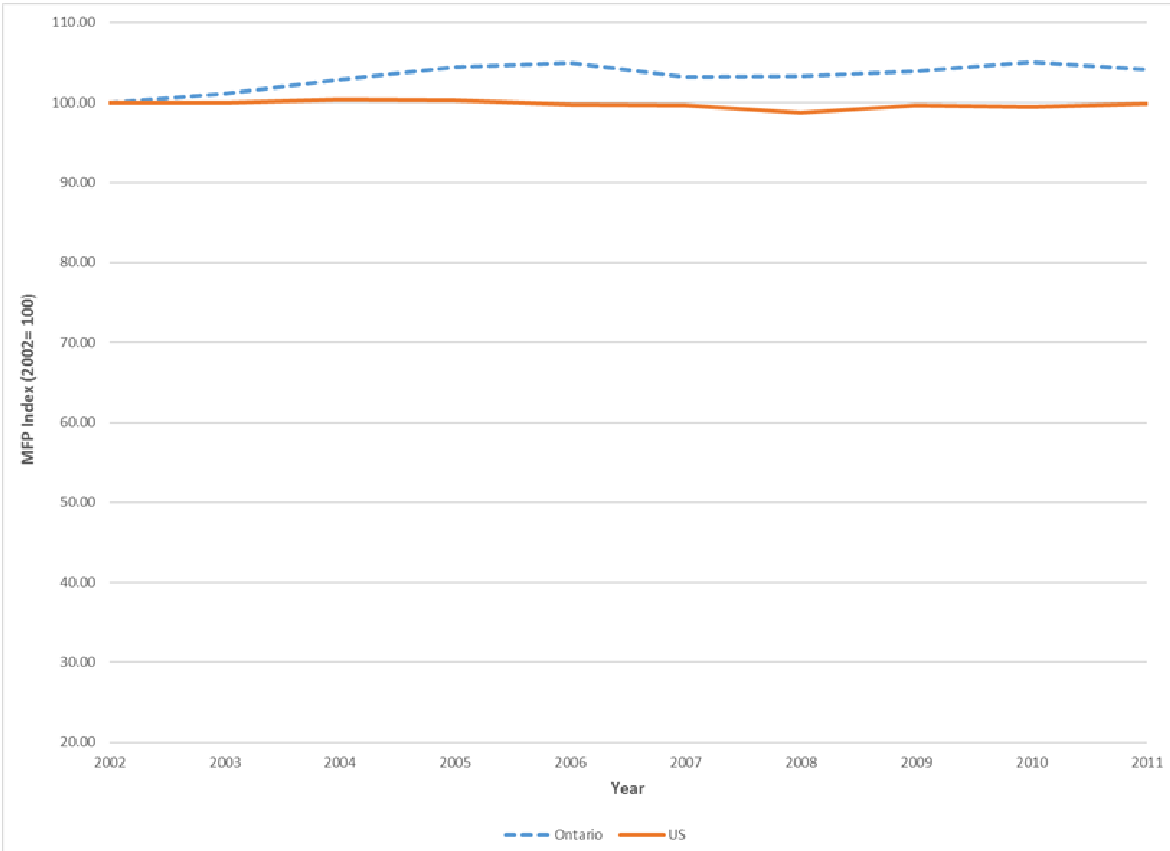

Figure 11. Comparison of Multifactor Productivity Trends of Ontario Distributors and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of Ontario distributors exceeded the industry norm under MRPs.

Consolidation

Since the late 1990s, Ontario's power distribution industry has consolidated from more than 200 distributors that existed prior to PBR to about 70 distributors. Hydro One Networks has purchased more than 80 distributors. The Ontario government has noted on several occasions that the industry could become more efficient with greater distributor consolidation. Consolidation may have spurred productivity growth.

Service Quality

Effects of the Ontario MRPs on utility service quality are unclear, potentially a result of data the Board has been gathering. Reported reliability metrics do not exclude major events, leading to potentially large year-to-year variations in performance due to weather events beyond distributors' control. In addition, the period of operation under MRPs (2005–2012) has witnessed the rollout of AMI and SCADA systems. These deployments are often linked to a worsening of measured reliability because more outages are detected by automatic reporting systems.

Some observers have suggested that Ontario distributors had high levels of service quality at the beginning of the MRPs, even to the point of arguing that some utilities had engaged in "gold-plating" their systems. These observers find that during the 2000s, which encompassed IRM1, a rate freeze, and IRM2, reliability suffered.

> [R]eliability has declined continuously from 2000 to 2008; degradation has become progressively worse. Results in the middle years [during the rate freeze] (2003-2005) are significantly worse than the earlier [IRM1] years (2000-2002), and results in the last years (2006-2008) [in which rates were reset and IRM2 was in effect] significantly worse than the middle.[155]

A 2010 Board staff report presented more mixed results:

> The [customer] surveys indicate that the majority of consumers are generally satisfied with current levels of system reliability, with 89% of residential consumers and 92% of business consumers reporting that they are "somewhat satisfied" or "very satisfied" with the reliability of electricity supply. However, over 75% of respondents in both groups indicated that, despite being generally satisfied, they still believe it is important for distributors to continue to work to reduce the number of outages…. There was a strong consensus amongst many participants that the Board should focus on ensuring that system reliability levels are maintained. These participants believe that the current regime is adequate for the purposes of ensuring continued sustainability and reliability…. Ratepayer groups that supported the development of a new reliability regime were in the minority. Some ratepayer representatives suggested that reliability has declined almost continually over the last 8 years.[156]

6.8 Power Distribution MRPs in Great Britain[157]

The power distribution industry of Great Britain also has a history very different from that of the United States. Until 1990, British electric utilities were not investor-owned. In the intervening years, these utilities have been privatized and restructured into separate generation, transmission and distribution operations. End users are billed by retailers, not distributors. This arrangement reduces the role of distributors in provision of DSM programs. Regulatory requirements of British utilities are codified in their licenses, rather than tariffs, administrative codes or laws.

There are currently 14 power distributors, eight gas distributors, three electric transmitters and one gas transmitter in Britain. The sizable task of regulating these utilities has been assigned to the Office of Gas and Electricity Markets (Ofgem). Ofgem also regulates gas and electric commodity markets.

[155] Cronin and Motluk (2011).
[156] Ontario Energy Board (2010), p. 7–10.
[157] A 2016 Berkeley Lab report (Lowry and Woolf) discussed the British system of energy utility regulation. This section provides additional history and plan design details and discusses notable outcomes.

Since privatization, British energy utilities have operated under a sequence of MRPs called *price controls.* The British approach to price controls has its roots in a 1983 document by British economist Stephen Littlechild, which relied on five criteria to evaluate regulatory options:[158]

- protect against monopoly power
- encourage efficiency and innovation
- minimize regulatory cost
- promote competition
- maximize proceeds from privatization

Traditional cost of service regulation was rejected by policymakers after scoring poorly on four of the five criteria. The one criteria where cost of service regulation performed well was protecting against monopoly power.

Littlechild proposed to regulate rate growth with an index using an inflation – X formula. Regulators have refined various features of the plans over the years in their periodic price control reviews. To date there have been five completed generations of price controls, with the sixth price control beginning in 2015. Ofgem undertook a substantial review of its regulatory practices beginning in 2008. The revised regulatory system that resulted from these deliberations is called *RIIO* (Revenues = Incentives + Innovation + Outputs).

Plan Design

Plan Term

British MRPs have traditionally had five-year terms. With the adoption of RIIO, the term of plans was extended to eight years. This strengthens performance incentives but has complicated the task of developing and reviewing plans.

Attrition Relief Mechanism

Price controls for power distributors in Britain originally featured price caps but now feature revenue caps. Caps of both kinds have been escalated by hybrid methods. Allowed revenue trajectories are established based on multiyear total cost forecasts. Principal components are forecasts of the value of the current capital stock and of capital spending, depreciation, the return on capital, and O&M spending. Because of the focus on component costs, the British approach to ARM design is sometimes called the *building block* method.

Britain's Retail Price Index (RPI) has been used as the inflation measure of the revenue cap indexes. Given forecasts of total cost, billing determinants and inflation, past plans have selected combinations of initial rates and an X factor such that forecasted revenue equals forecasted cost. The revenue cap escalator in RIIO has an implicit X factor of zero.

Use of forecasts to establish allowed revenue led to concerns by Ofgem and its predecessor, the Office of Electricity Regulation, about utility exaggerations of capex requirements. For example, underspends occurred in a period when utilities had forecasted high capex due to an "echo effect" when facilities installed in a past capex surge approached the end of their service lives. In its 1994–1995 price control review, the regulator accepted the need for a high level of replacement capex, noting that facilities from a

[158] Littlechild (1983). Littlechild subsequently served as director general of the electricity regulator.

prior capex surge were approaching retirement age. The regulator nonetheless reduced individual company total capex proposals by as much as 25 percent because not all of the capex was deemed necessary.

In its next price control review, the agency compared distributors' actual capex during the expiring price control to the budgets that had been approved. Figure 12 shows that actual capex was lower than the regulator's approved levels. The regulator came to the conclusion that the "echo effect" was less pronounced than it had expected.[159]

The regulator suspected that some utilities had misrepresented their capex needs. This experience encouraged the regulator to consider some implications of extensive capex underspends in developing a new price control.[160] Ofgem began by reassessing its policy on underspending:

> Ofgem would expect such companies to retain the benefit of their under-spend. Given that, to a significant extent, the nature and timing of capital expenditure (particularly non-load related expenditure) is discretionary, measures need to be introduced to ensure that companies are only rewarded for genuine efficiency not timing benefits obtained through manipulation of the periodic regulatory process.
>
> In this context, it is particularly important to ensure that companies do not have a perverse incentive to 'achieve' periodic delays in capital expenditure, such that they regularly under-spend Ofgem's forecasts, thereby gaining a financial benefit, and then claim a higher allowance for the subsequent period in respect of the capital expenditure which has not been undertaken.… Further where [distributors] underspend in one period and then forecast an increase in expenditure in the next, this will be carefully scrutinized.[161]

The regulator further stated that:

> The unavoidable information asymmetry between regulator and regulated companies is a major issue especially since, under the present regime, regulated companies have an incentive to overstate required expenditures when discussing future price controls with the regulator.[162]

[159] Offer (1999), p. 46.
[160] During the course of the proceeding, Offer merged with the British gas regulator Ofgas to become Ofgem.
[161] Ofgem (1999), p. 41.
[162] Ofgem (1999), p. 7.

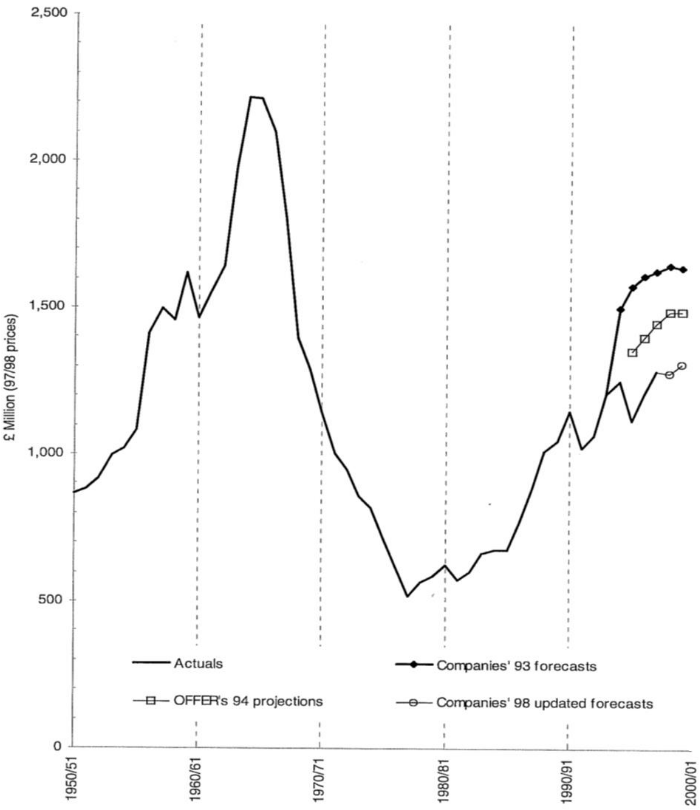

Figure 12. Distribution Business Capital Expenditures (1997/98 Prices). A capex surge during the period 1993–2000 was due to an "echo effect" from a past capex surge that was lower than forecasted.[163]

Ofgem penalized three distributors in its final decision which had provided exaggerated forecasts of capex and operating expenditures (opex). Nevertheless, it became apparent that forecasting overstatements had continued. Ofgem found that capex was being underspent by utilities under the first three years of the new price control.[164] Many power distributors were also providing forecasts describing a need for capex that was more than 20 percent greater than previous forecasts.[165]

Due in part to such experiences, Ofgem has over the years commissioned numerous statistical benchmarking and engineering studies to develop its own independent view of required cost growth. In 2004, Ofgem added to rate plans an Information Quality Incentive (IQI) to encourage more accurate capex forecasts. This complicated PIM, an example of an incentive-compatible menu, is discussed further in Appendix A.3.

Distributors that have well-justified business plans at an early stage of the RIIO proceeding can be "fast-tracked." Fast-tracking allows the distributor to receive approval of its business plans as much as a year earlier than would otherwise be the case and avoid more intense scrutiny of its business plan. This enables the distributor a greater opportunity to focus on executing its business plan during the run-up to the new MRP.

Another innovative feature of RIIO is its focus on total expenditures (totex) to level the playing field between capex and opex. Ofgem has explained the rationale for a totex focus:

[163] Offer (1999), p. 45.
[164] Ofgem (2004a).
[165] Ofgem (2004b).

> The incentives to manage different types of costs under the price control are not equal. These imbalances may distort the decisions that [distributors] need to make between capex and opex solutions and create boundary issues. This is not in customers' interests as it may lead to [distributors] seeking to outperform the settlement by favoring capex over opex (or vice versa). This may lead to inefficient network development and higher charges for customers in the short or long term….
>
> These rules create two undesirable effects:
>
> - Incentives are distorted toward adopting capex rather than opex solutions. This means that [distributors] are not incentivized to minimize total lifetime costs as they are sometimes better off by adopting a capex solution rather than a cheaper opex solution due to the way that the different expenditures are treated.
>
> - Boundary issues are created. There is an incentive to record expenditure in the areas with the highest rates of capitalization even if the expenditure was not technically in that area. This requires significant policing of the cost reporting of [distributors].[166]

To address these problems, Ofgem decided to equalize the incentives between opex and capex for most cost categories.[167] Instead of traditional expensing and capitalization rules, Ofgem fixed the amount of total expenditures that could be capitalized at 85 percent. Newly capitalized costs would be recovered over a 45-year period, while existing rate base costs would be recovered over a 20-year period. The remaining 15 percent would be expensed.

<u>Performance Metric System</u>

RIIO features complicated performance metric systems that include several PIMs. Metrics in this system are called *outputs.* The performance incentive mechanisms in RIIO place a sizable share of distributor revenue at risk, prompting some commentators to call RIIO a "results-based" approach to regulation. However, the unusually large sensitivity of earnings to performance mechanisms in RIIO is due mainly to the Information Quality Incentive.

With respect to service quality, Ofgem adopted guaranteed reliability standards early on, later adding guaranteed standards of performance for connections. One example of a guaranteed standard is that distributors are required to restore service within 12 hours in normal weather conditions. Distributors must make predetermined payments directly to customers each time a minimum performance standard is not met. Ofgem also developed a reliability PIM called the *Interruptions Incentive Scheme* that addresses distributors' outage frequency and duration performance.

Ofgem has expanded its customer satisfaction PIM over the years into a Broad Measure of Customer Satisfaction. This encompasses the number of complaints that a distributor has and an assessment of customer satisfaction with distributors' responsiveness with regard to outages, connections and general inquiries. Ofgem has also experimented with PIMs to encourage reductions in line losses.

Distributors are required to report annually on numerous additional metrics. These have expanded over the years from cost and revenue reporting to include measures that are not commonly reported in the United States, including the health of assets, substation utilization levels and air emissions. Business

[166] Ofgem (2010), p. 107.
[167] Costs that were not provided this treatment include many types of administrative and general expenses, pensions and several costs that receive supplemental funding, discussed later in this section.

Carbon Footprint metrics include distributors' annual electricity losses in addition to their direct carbon emissions.

Ofgem reviews distributors' annual reports on these metrics and issues its own report summarizing distributors' performance. Reports feature a scorecard with "traffic lighting," using red to indicate poor performance, green to indicate good performance, and yellow to indicate performance in between.

RIIO also changed asset health metrics into a risk index. The risk index is a composite measure of asset health and criticality indexes, reflecting risks of asset failures for a distributor. The asset health index measures the likelihood of an asset failure, while the criticality index measures the impact of a potential asset failure. The risk index has become the basis for a PIM with a possible penalty or reward of 2.5 percent of avoided or incurred costs.

RIIO has also increased use of discretionary financial incentives. A stakeholder engagement incentive encourages distributors to engage with customers and incorporate their input in decisions and to identify vulnerable customers and take efforts to ensure their energy needs are met. An incentive for connections engagement assesses a distributor's effort in formulating and pursuing strategies for providing and improving connection services to large customers, as well as a distributor's use of information learned from these customers to improve these services. A load index measures substation loading on a distributor's primary network.

Revenue Decoupling

While being described as a "price control," Ofgem today uses revenue caps. A "correction factor" refunds or charges customers for variances between actual and allowed revenue. In past plans, sales volume and customer growth increased the company's allowed and actual revenue to some extent.[168] However, this linkage was eventually eliminated, resulting in revenue decoupling that continues through RIIO today.

Cost Trackers

British MRPs often feature mechanisms similar to cost trackers for various costs that are difficult to control. For example, most pension costs have been tracked. Trackers also have been put in place for an assortment of special projects including load reinforcement, high value projects and rail electrification. Supplemental revenue can only be requested at one or two prespecified periods during the rate plan. Another variant on cost trackers is supplemental allowances that distributors can access for specific projects. These allowances have been developed for various purposes, including improvement in the reliability of service to "worst served customers," workforce renewal, distributor innovation efforts, and to encourage distributors to begin making changes toward a low carbon future.

Outcomes

From 2008–2010, as part of the RPI-X@20 process to modernize its regulatory system, Ofgem undertook an extensive review of effects of its price controls. Reviews are also held at the end of each price control. In these reviews, Ofgem indicated that many MRP features had functioned well. For example, in 2009 the regulator stated:

> We have found that allowed revenue have declined since RPI-X regulation was introduced and we expect network charges to have followed a similar trend. Improvements in operating

[168] The percentage of revenue growth tied to the growth in revenue drivers, including customer and sales growth, was determined for each rate plan.

efficiency and stability in the allowed cost of capital have facilitated these declines. Capital investment has been increasing and the reliability of the supply to customers has improved. These have all been driven at least partly by the regulatory framework…

> Our analysis reveals changes in recent years, however. Allowed revenue has stabilized or increased, reflecting increased investment. Operating efficiency improvements are expected to continue, but the scale may be limited compared to the period since RPI-X regulation...

> We have also found evidence that the regulated networks have generally managed to beat the regulatory settlement. Whilst this in itself is not necessarily cause for concern, there are questions about the extent to which companies are able to outperform and whether those companies earning the highest returns are indeed those that perform best for consumers.[169]

Cost Performance

Studies of multifactor productivity trends of British power distributors like those we have undertaken for North American distributors have been hampered by poor data. In particular, a consistent time series dataset is not available for many years, as the definitions of costs have changed over time.[170]

Ofgem commissioned a study of historic and expected productivity trends of British power distributors and the U.K. economy.[171] The study found that from program year 1991–1992 to program year 2001–2002, the British distributors averaged annual MFP growth of 4.3 percent. The opex productivity trend was 7.9 percent while the capital productivity trend was 1.2 percent. These MFP results were substantially higher than those of the U.K. economy as a whole and U.S. power distributors for similar time periods. However, the MFP measurement methodology was different.

In its RPI-X@20 review, Ofgem found that during the course of the price controls, real controllable operating costs per unit of energy distributed declined by 3.1 percent per year.[172] This decline exceeded the targets set by Ofgem in the price control reviews. In addition, distributors often underspent their capex budgets.

A major focus of Ofgem reviews of distributors' performance is comparisons of actual and allowed spending. The regulator found that 12 of 14 distributors had underspent their allowance. Ofgem attributed this outcome to several factors: improvements in efficiency, with unit costs for asset replacement work falling significantly; falling input prices; and a drop in reinforcement, connection and high value projects due to economic conditions. However, distributors had not delivered on their commitments in some areas, such as flood risk reduction programs.[173]

Reliability

The RPI-X@20 review assessed the reliability performance of power distributors under price controls. It found that the frequency and duration of outages had declined about 30 percent between 1990 and 2008. These trends continued, with a further 20 percent reduction in outage frequency and 30 percent reduction in outage duration between program year 2009–2010 and program year 2014–2015.[174]

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[169] Ofgem (2009a), p. 26.
[170] Ofgem (2009e).
[171] Information comparable to what we have gathered on the MFP trends of U.S. power distributors is unavailable.
[172] Real controllable operating costs were defined as operating costs less depreciation and "atypical" items.
[173] Ofgem (2015), p. 22.
[174] Ofgem (2015), p. 45.

RIIO

In February 2017, Ofgem released its first annual report on experience under RIIO.[175] The regulator reported that 12 of 14 distributors were spending less than they were allowed.[176] After the first year, distributors expected to underspend their allowances by 3 percent for the entire term of RIIO.

The report also noted that distributors had managed to over-earn by about 300 basis points on average. Ofgem believed that ROE performance was "predominantly driven by all [distributors] performing well against the Interruptions Incentive Scheme."[177] All distributors earned rewards under the scheme.

Distributors also had strong performances in several other areas:

- All distributors decreased their business carbon footprint and sulfur hexafluoride leaks during the first year of RIIO.

- Distributors also significantly improved their times to quote new connections. The industry average for the first year of RIIO was 46 percent to 49 percent lower than the target.[178]

- No distributors were penalized under the Incentives on Connections Engagement, as Ofgem was pleased with quality and detail of distributors' submissions.

All distributors received awards from the Broad Measure of Customer Service, and only one distributor was penalized as a result of poor customer satisfaction survey score.

[175] Ofgem (2017).
[176] On average, the distributors spent 9 percent less than their allowance for the first year of RIIO. These areas of underspending were partly offset by increased spending on inspections, repairing faults on the networks, and service quality.
[177] Ofgem (2017), p. 13.
[178] Ofgem (2017), p. 33.

7.0 Conclusions

The electric utility industry has played a key role over the years in the high performance of the U.S. economy. The industry was largely built under the cost of service approach to utility regulation. This regulatory system sets base rates in general rate cases at levels that compensate utilities for the costs they incur for capital, labor and materials. The scope of trackers that expedite recovery of utility costs has expanded in some jurisdictions to encompass costs of capital and other base rate inputs, as well as energy.

We have shown in this report that the efficacy of cost of service regulation (COSR) varies with business conditions. When conditions favor utilities, as often was the case in the years when COSR became an American tradition, rate cases are infrequent, performance incentives are strong, and regulatory cost is restrained. When business conditions are unfavorable, utilities file frequent rate cases or seek tracker treatment for more costs, or do both. As a consequence, performance incentives are weaker and regulatory cost is higher.

Multiyear rate plans are a salient alternative to COSR for electric utilities. Extensive experience has accumulated with these plans. Regulators have typically approved MRPs on the grounds that they strengthen performance incentives while reducing regulatory cost. Plans have had diverse provisions, and extensive experimentation has occurred.

MRPs can improve the efficiency of regulation. With less time spent on general rate cases, costs of regulation can be reduced, or resources can be redeployed to other useful activities like rate design and distribution system planning. In principle, MRPs that do not impair utility performance or harm customers could be adopted solely on the basis of better regulatory efficiency.

It is difficult to assess the impacts of MRPs and rate case frequency on utility cost performance. Costs of utilities are, after all, influenced by many other business conditions (e.g., severe storms and system age) as well as by their regulatory system. This report reviewed impacts of regulation on utility cost performance using two analytical tools: numerical incentive power analysis and empirical research on utility productivity trends.

Both lines of research suggest that MRPs (and, more generally, infrequent rate cases) can materially improve utility cost performance. For example, multifactor productivity growth of the U.S. electric, gas and sanitary sector was found to be considerably slower relative to that of the economy in a period of frequent rate cases than it was in periods when rate cases were much less frequent. We also found that the MFP growth of investor-owned electric utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the U.S. electric utility norm. Stronger incentives produced cost savings of 3 percent to 10 percent after 10 years.

Our incentive power research suggests that *modest* steps in the direction of MRPs from traditional regulation produce only modest improvements in utility cost performance. This is also consistent with our empirical research, which showed that the MFP growth of California and New York utilities, which typically operated under conservative MRPs, were similar to or worse than the U.S. electric utility norm on balance. More robust MRPs — such as those with five-year plans, no earnings sharing, efficiency carryover mechanisms, and avoidance of rate cases between plans — can potentially produce larger gains. Recent innovations in MRP design, such as advances in efficiency carryover mechanisms, can increase incentive power.

Our incentive power research and case studies have important implications. First, utility performance and regulatory cost should be on the radar screen of state utility regulators, consumer groups and utility managers. We have shown that key business

conditions facing utilities today are less favorable than in prior periods when COSR worked well. This can lead to increased rate case frequency and expanded use of cost trackers which weaken utility incentives for improved cost performance.

Notwithstanding potential benefits of MRPs, they have not been adopted for energy utilities in most U.S. jurisdictions.[179] Several reasons can be advanced.

- COSR is well established in the United States, and some commissions are accomplished practitioners. When challenges emerge to the continuation of COSR, quick fixes such as revenue decoupling to address problems related to declining average use and expanded use of cost trackers have been more appealing to many regulators than the more extensive changes required to implement MRPs. State regulators also have tended to resist sweeping change in the direction of cost-plus regulation such as formula rate plans.

- Continuing evolution of COSR will slow diffusion of MRPs. For example, capital cost trackers can be incentivized. Use of PIMs to encourage cost-effective use of DERs can be expanded.

- It can be difficult to design MRPs that generate strong utility performance incentives without undue risk and that share benefits of better performance fairly with customers.

- Some adverse conditions (e.g., need for high capex) which give rise to frequent rate cases and expansive cost trackers under COSR have proven challenging to accommodate under MRPs.

- MRPs invite strategic behavior and plan design controversies. The dollars at stake invite stakeholders to energetically defend their positions. In proceedings to approve plans with indexed ARMs, for example, controversy over X factors has been common.

- Transitional regulatory systems that limit risks of bad outcomes from MRPs through such means as earnings sharing mechanisms and relatively short plan terms often do not generate substantially greater performance improvements than traditional COSR.[180]

- Utilities in most states have not proposed MRPs. While this may reflect their perception of the regulatory climate in their jurisdictions, many utilities may believe that they will make more money (or make the same money more easily) from frequent rate cases and more expansive cost trackers than under an MRP.

- Many consumer advocates are unsure of their role in an MRP system of regulation. Under COSR, consumer advocates intervene in each general rate case to reduce the revenue requirement. The substantial long-term cost to customers of slow productivity growth due to COSR is less visible. The lost opportunity for consumer advocates to spend more time on other regulatory issues may also be underappreciated.

- A key advantage of MRPs is the ease with which they can address brisk inflation. However, inflation has been slow in recent years.

- The impetus for PBR in many countries has come more from regulators and other policymakers than it has from utilities. Regulatory commissions in U.S. states typically have a less daunting

[179] For another discussion of why MRPs are not more popular in the United States, see Costello (2016).
[180] These transitional plans may nonetheless be important stepping stones to more effective regulatory systems.

mandate than regulators in other countries, who often have national jurisdictions with numerous utilities. This reduces the appeal of streamlined regulation.

Notwithstanding these considerations, we believe that use of MRPs is likely to increase in electric utility regulation over time.

- Key business conditions that trigger general rate cases are more likely to deteriorate than to improve in coming years. For example, inflation is more likely to rebound than to slow further due, for example, to rising bond yields. Penetration of customer-side DERs is likely to increase.

- Use of MRPs is already growing in the regulation of vertically integrated U.S. electric utilities.

- Continuing innovation in the United States, Canada and other countries will produce better MRP approaches. For example, regulators are becoming more skilled at designing plans for utilities engaged in accelerated grid modernization. Incentive compatible menus and efficiency carryover mechanisms help to ensure customer benefits.

- A growing number of power distributors will complete accelerated modernization programs and enter a period of more routine capex requirements that pose fewer problems for MRP design.

The strengths and weaknesses of MRPs are not fully understood. Plan design continues to evolve to address outstanding challenges. Areas of recommended future research include impacts of MRPs (and reduced rate case frequency more generally) on service quality, operating risk, and levels of bills that customers pay.[181] Evidence gathered for this report suggests that MRPs did not impair reliability, but this evidence was anecdotal. Lack of data is a major barrier to more comprehensive research on reliability and bill impacts.

[181] In addition, more refined statistical tests of the impacts of MRPs can be devised.

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Appendix A. Further Discussion of Multiyear Rate Plan Designs

This appendix discusses some topics in incentive plan design in greater detail. We consider earnings sharing mechanisms (ESMs), Z factors, marketing flexibility and Ofgem's Information Quality Incentive.

A.1 Earnings Sharing Mechanisms

Earnings sharing mechanisms share earnings variances that arise when a utility's return on equity (ROE) deviates from a commission-approved target. Treatment of earnings variances may depend on their magnitude. For example, there are often dead bands in which the utility does not share smaller variances (e.g., less than 100 basis points from the ROE target) with customers. Beyond the dead band there may be one or more additional bands in which earnings are shared in different proportions between customers and the utility.[182] While some ESMs share both surplus and deficit earnings, others share only surplus earnings. This maintains an incentive for companies to become more efficient to avoid under-earning.

Whether or not to add an ESM is one of the more difficult decisions in multiyear rate plan (MRP) design. The offsetting pros and cons of ESMs may help to explain why they are only featured in about half of current U.S. and Canadian MRPs. On the plus side, an ESM can reduce risks that revenue will deviate substantially from cost. Unusually high or low earnings may be undesirable to the extent that they reflect windfall gains or losses, poor plan design, data manipulation, or strategic deferrals of expenditures. Reduced likelihood of extreme earnings outcomes can help parties agree to a plan and make it possible to extend the period between rate cases.

On the downside, ESMs weaken utility performance incentives. Permitting marketing flexibility can be complicated in the presence of an ESM because discounts available to some customers can affect earnings variances that are shared with all customers.[183] ESM filings can be a source of controversy. Customers may complain, for example, if the ROE never gets outside the dead band so that surplus earnings are shared. There is less need for an ESM if the plan features other risk mitigation measures such as inflation indexing, Z factors or revenue decoupling.

A.2 Z Factors

A Z factor adjusts revenue for miscellaneous hard-to-foresee events that impact utility earnings. Many MRPs have explicit eligibility requirements for Z factor events. Here is a typical list of requirements.

Causation: The costs must be clearly outside of the base upon which rates were derived.

Materiality: The costs must have a significant impact on utility finances. Materiality can be measured based on individual events, cumulative impacts of multiple events, or both.

[182] An ESM is therefore sometimes referred to as a "banded ROE."
[183] This problem can be contained by sharing only the utility's earnings surpluses.

Outside of Management Control: The cost must be attributable to events outside of management's ability to control.

Prudence: The cost must have been prudently incurred.

One of the primary rationales for Z factor adjustments is the need to adjust revenue for effects of changes in tax rates and other government policies on the utility's cost. Another rationale for Z factors is to adjust for effects of miscellaneous other external developments on utility costs which are not captured by inflation and X factors. Z factors can potentially reduce operating risk, without weakening performance incentives for the majority of costs. Z factors can thus reduce the possibility that an MRP needs to be reopened, while maintaining most benefits of MRPs.

A.3 Marketing Flexibility

Need for Flexibility

Regulators have long acknowledged the need to afford utilities some flexibility in fashioning rate and service offerings. A utility's need for marketing flexibility is greater to the extent that demand for its services is complex, changing and elastic (i.e., sensitive) with respect to the terms of services offered. When demand is elastic, rates that are too high produce more bypass of utility services.[184] Demand elasticity is greater when customers have alternative ways to meet their needs which are competitive with respect to cost and quality. Elasticity is also greater for products that are "discretionary" in the sense that they do not address a customer's most basic needs.

While "core" customers have fewer options and lower elasticities of demand for basic services, electric utilities have long relied on marketing flexibility to customize terms of service to large-volume customers. These customers play a larger role in the earnings of VIEUs than they do in the earnings of UDCs. One reason is that UDCs do not profit from sizable sums these customers pay for power supplies. Another is that some of these customers take service at transmission voltage and do not pay for many distribution-level costs. In addition, all types of utilities desire flexibility when marketing underutilized capacity in competitive markets (e.g., leasing land in transmission corridors).[185]

Interest among electric utilities in marketing flexibility is growing as demand for power services is becoming more complex, changeable and sensitive to terms of service that utilities offer. For example, advanced metering infrastructure, other smart grid technologies, distributed storage, and plug-in electric vehicles open the door to a variety of new utility services. Large-load customers have a growing interest in customized green power services to meet corporate goals. Distributed generation and storage pose a growing competitive challenge in some jurisdictions. However, for the foreseeable future regulators will likely control terms of service to distributed generation and storage customers carefully.

Marketing flexibility can also help utilities encourage customers to use their services in less costly ways. For example, AMI makes it more cost-effective to offer time-varying tariffs to

[184] Uneconomic bypass occurs when a customer would use a system more at a lower rate that still exceeds the cost of service. When uneconomic bypass is reduced, customers make more contributions to fixed costs that lower rates for other customers.
[185] Margins from "other revenues" benefit retail customers by, for example, reducing the retail revenue requirement in rate cases.

residential and small business customers. These tariffs can encourage reduced loads at times when the cost of electricity is especially high and slow the need for costly upgrades for substations and load-following generation capacity.

Flexibility Measures

Marketing flexibility runs the gamut from greater effort by regulators to approve new rates and services by traditional means to "light-handed" regulation and even decontrol of certain utility offerings.[186] Light-handed regulation typically takes the form of expedited approval of new or revised rate and service offerings. These offerings may be subject to further scrutiny at a later date, such as in the next rate case. Pricing floors are often established based on marginal or incremental cost of service to ensure that customers of new rates and services contribute to margin.

Regulators most commonly grant marketing flexibility for rate and service offerings with certain characteristics. Generally speaking, flexibility is encouraged where new offerings are likely to benefit target customers while also benefitting other customers — for example, by increasing contributions to margins so that contributions by other customers can be reduced. Optional offerings have often been accorded expedited treatment by regulators because targeted customers are protected by their recourse to service under standard tariffs, as well as offerings by potential third-party providers that compete with the utility.

Several kinds of offerings may be deemed optional, such as:

1. A discount from rates in a standard tariff, offered to particular customers — for example, due to relatively high elasticity of their demands for utility services

2. An optional tariff that is available to all qualifying customers, such as a time-sensitive rate for electric vehicle charging

3. Special (negotiated) customer-specific contracts for utility services

4. A new premium quality service for customers prepared to pay for better quality

5. A discretionary service such as lighting on a backyard power pole

6. Special service packages (which may include standard services as components), such as a rate for a bundle of services that includes premium quality service and electric vehicle charging

Why MRPs Facilitate Marketing Flexibility

MRPs facilitate marketing flexibility for several reasons. Less frequent general rate cases reduce the chore of deciding how to allocate the revenue requirement between a complex and changing mix of market offerings. Multiyear rate plans also reduce concerns about cross-subsidies between service classes because infrequent rate cases and other plan provisions, such as service baskets, insulate core customers from potentially adverse consequences of marketing flexibility.[187] To the

[186] Decontrol of utility rate and service offerings is typically limited to markets that are robustly competitive.
[187] Cost trackers create a "back door" to cross-subsidization unless discounting of tracked costs is prohibited.

extent that the utility's earnings losses from special terms of services for certain customers can't be recovered from other customers, regulators are more confident that discounts are prudent.

In addition to facilitating marketing flexibility, MRPs create a special need for flexibility since rate cases are less frequently available as occasions for redesigning rates. Special proceedings to redesign rates in a revenue-neutral way can occur during an MRP. Alternatively, utilities may be permitted (or required) to gradually change rate designs during a rate plan in accordance with commission-approved goals. For example, the commission could approve a phase-in of time-sensitive usage charges.

MRPs can also strengthen utility incentives to improve marketing because the utilities are able to keep resultant margins longer. For example, under MRPs utilities have greater motivation to discourage load patterns that are especially costly. Under price caps, utilities have more incentive to encourage large-load customers to expand their operations.

Marketing Flexibility Precedents

Electric utilities have long been granted flexibility by regulators in rates and services they offer to some of the markets they serve. For example, rates utilities charge for use of their assets in various competitive markets are frequently not addressed by state regulators. Examples include sales in bulk power markets and rental of surplus office space. Light-handed regulation is sometimes accorded to special contracts for large-load customers with price-elastic demands or an interest in customized green power services.[188] However, special contracts for utility services require specific approval in many jurisdictions.

Multiyear rate plans have been extensively used to regulate utilities in industries where market-responsive rates and services are a priority. The example of Central Maine Power is discussed in Section 6 in this report. However, MRPs have not to date played a large role in fostering electric utility marketing flexibility. One reason is that many MRPs to date have applied to utility distribution companies, which traditionally had less need for special pricing for large-load customers.

A.4 Britain's Information Quality Incentive

Britain's Information Quality Incentive (IQI) rewards distributors for making conservative cost forecasts and then performing better.[189] The IQI is essentially a menu consisting of cost forecast-allowed revenue combinations. It currently applies to most operation and maintenance (O&M) expenses and capex. Each utility is asked to give a cost forecast and is eventually given an allowed revenue amount based on this forecast. The IQI's input on allowed revenue is in two parts: *ex-ante* allowed revenue and an IQI adjustment factor. By announcing its cost forecast, the utility implicitly chooses both its *ex-ante* allowed revenue and an IQI adjustment factor formula.

The *ex-ante* allowed revenue is a weighted average of the regulator's and the utility's cost forecasts. The regulator's forecast receives 75 percent weight while the utility's forecast receives

[188] Duke Energy (2015).
[189] Ofgem states that distributors with "less well justified capex forecasts, as compared with the views of Ofgem's consultants would be permitted to spend above the amounts that they had justified to Ofgem but [these distributors] would receive relatively lower returns for underspending. In contrast, those [distributors] that had better justified their forecasts, and were in line with the views of the consultants, would be rewarded with a higher rate of return and a stronger incentive for efficiency." See Ofgem (2009b), p. 38.

25 percent weight. This treatment alone greatly reduces the payoff to the distributor from a high cost forecast. The substantial weight assigned to the regulator's forecast reflects the large investment it makes in engineering and consulting services to develop an independent review of future cost.

The IQI adjustment factor is composed of an incentive rate and an additional income factor. The incentive rate specifies sharing, between utilities and customers, of variances between the utility's actual expenditures and the allowed revenue for these expenditures it was granted *ex ante*. The utility's share of these variances increases as the difference between the utility's cost forecast and regulator's own forecast decreases. The additional income factor, also referred to as an upfront reward or penalty, provides an immediate incentive for the utility to provide a cost forecast that is at or below Ofgem's own forecast.

Together these provisions make the menu "incentive compatible." The utility is rewarded when its cost forecast is low and its actual cost is similar. The IQI discourages a strategy of proposing a high forecast and subsequently incurring low costs.

Figure A-1 shows the IQI menu developed for the 2010-2015 plan:[190]

- The first row is a ratio of the utility's cost forecast to the regulator's cost forecast. A ratio of less than 100 means the utility has presented a lower cost forecast than the regulator, while a ratio above 100 means the utility's cost forecast is higher than the regulator's.

- The second row is the utility's share of what it over- or underspends relative to the *ex-ante* allowed revenue. The utility's share of these variances increases when its cost forecast is low. This feature provides greater incentives for the utility to cut costs and provide a forecast that is not inflated.

- The third row is the *ex-ante* revenue the utility can collect, expressed as a percentage of the regulator's cost forecast. This is much closer to Ofgem's forecast than to the utility's.

- The fourth row is the additional *ex post* income the utility can collect, expressed as a percentage of the regulator's cost forecast. This is a reward for a low cost forecast.

Values in the second section of Figure A-1, labeled IQI Adjustment Factor, illustrate possibilities for additional revenue (expressed as a percentage of Ofgem's cost forecast) which the utility can collect once it reports actual expenditures for the price control period. The amount of additional revenue depends on how the company's forecast compares to Ofgem's forecast and to the company's ultimate expenditures. The revenue adjustment is more favorable to the utility to the extent that its expenditures are low relative to its own forecast and Ofgem's forecast. The highest reward is offered for spending less than a utility forecast that was low relative to Ofgem's forecast.

[190] There have not been any major changes to the IQI methodology since this matrix was established.

Utility's cost forecast (% of Ofgem's cost forecast)	95	100	105	110	115	120	125	130	135	140
Utility's share of under/over spending (incentive rate)	0.53	0.5	0.48	0.45	0.43	0.4	0.38	0.35	0.33	0.3
Ex-ante allowed revenue (% of Ofgem's cost forecast)	98.75	100	101.25	102.5	103.75	105	106.25	107.5	108.75	110
Ex-post additional income (% of Ofgem's cost forecast)	3.09	2.5	1.84	1.13	0.34	-0.5	-1.41	-2.38	-3.41	-4.5
Actual utility expenditure (% of Ofgem's cost forecast)	**IQI Adjustment Factor (% of Ofgem's cost forecast)**									
90	7.69	7.5	7.19	6.75	6.19	5.5	4.69	3.75	2.69	1.5
95	5.06	5	4.81	4.5	4.06	3.5	2.81	2	1.06	0
100	2.44	2.5	2.44	2.25	1.94	1.5	0.94	0.25	-0.56	-1.5
105	-0.19	0	0.06	0	-0.19	-0.5	-0.94	-1.5	-2.19	-3
110	-2.81	-2.5	-2.31	-2.25	-2.31	-2.5	-2.81	-3.25	-3.81	-4.5
115	-5.44	-5	-4.69	-4.5	-4.44	-4.5	-4.69	-5	-5.44	-6
120	-8.06	-7.5	-7.06	-6.75	-6.56	-6.5	-6.56	-6.75	-7.06	-7.5
125	-10.69	-10	-9.44	-9	-8.69	-8.5	-8.44	-8.5	-8.69	-9
130	-13.31	-12.5	-11.81	-11.25	-10.81	-10.5	-10.31	-10.25	-10.31	-10.5
135	-15.94	-15	-14.19	-13.5	-12.94	-12.5	-12.19	-12	-11.94	-12
140	-18.56	-17.5	-16.56	-15.75	-15.06	-14.5	-14.06	-13.75	-13.56	-13.5
145	-21.19	-20	-18.94	-18	-17.19	-16.5	-15.94	-15.5	-15.19	-15

Figure A-1. IQI Matrix for Ofgem's 5th Distribution Price Control Review.[191] IQI Matrix is an incentive compatible menu intended to encourage utilities to make low expenditure forecasts and then outperform them.

Suppose, by way of illustration, that a utility made a forecast that was just 5 percent above Ofgem's. Its *ex ante* allowed revenue would be only 1.25 percent above Ofgem's forecast, but it would be entitled to a fairly high 48 percent of surplus earnings and additional income equal to 1.84 percent of Ofgem's forecast. If its actual cost turned out to be the same as its forecast, it would garner an additional reward equal to 0.06 percent of Ofgem's forecast.

[191] Ofgem (2009c), p. 111. Presented here with some small changes to be more easily understood.

Appendix B. Details of the Technical Work

This appendix provides more technical details of two lines of research presented in this report. One is the numerical incentive power research. The other is the empirical research on power distributor productivity. We also discuss some statistical benchmarking concepts.

B.1 Incentive Power Research[192]

This section discusses incentive power research that PEG has conducted over the years on behalf of several utilities and regulatory commissions.[193] Implications of this research are summarized in Section 5 of this report.

Overview of Research

Our incentive power research considers how the performance of utilities differs under alternative regulatory systems that feature various performance-based regulation (PBR) features as well as systems that resemble traditional rate regulation. The research can be used to explore multiyear rate plan (MRP) design options such as earnings sharing mechanisms and alternative plan terms.

At the heart of our research is a mathematical optimization model of the cost management of a company subject to rate regulation. We consider a company facing business conditions like those of a large energy distributor. In the first year of the decision problem, we assume for our example calculations that total annual cost is around $500 million for a company of average efficiency. Capital accounts for a little more than half of total cost. The annual depreciation rate is a constant 5 percent, the weighted average cost of capital is 7 percent, and the income tax rate is 30 percent.

Some assumptions have been made in the model to simplify the analysis. There is no inflation or output growth that would cause cost to grow over time.[194] The utility's revenue will be the same year after year in the absence of a rate case.

The company has opportunities to reduce its cost through cost reduction initiatives. Two kinds of cost reduction projects are available. Projects of the first type lead to temporary (specifically, one-year) cost reductions. Projects of the second type involve a net cost increase in the first year in exchange for *sustained* reductions in future costs. Projects in this category vary in their payback periods. The payback periods we consider are one year, three years and five years. For projects of each kind, there are diminishing returns to additional cost reduction effort in a given year. In total, we consider eight kinds of cost reduction projects — four for O&M expenses and four for capex. In our simulations, the company is permitted to pass up each kind of project in a given year (so that there is zero effort) but cannot choose *negative* levels of effort which constitute deliberate waste. This is tantamount to assuming that deliberate waste is recognized by the regulator and disallowed.

The company can increase earnings by undertaking cost containment projects, but experiences employee distress and other *unaccountable* costs when pursuing such projects. These costs are assumed to occur in

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[192] Further details of this research can be requested from the authors.
[193] Our research in this area was for several years spearheaded by Travis Johnson, a graduate of the Massachusetts Institute of Technology and Stanford Business School who is now a professor at the McCombs School of Business at the University of Texas.
[194] The comparatively low weighted-average cost of capital reflects these assumptions.

the first year of the initiative. We have assigned these unaccountable costs a value, in the reckonings of management as it crafts a business plan, that is about one quarter the size of the *accountable* upfront costs.

The company is assumed to choose the cost containment strategy that maximizes the net present value of earnings, less the unaccountable costs of performance improvement just discussed, given the regulatory system, income tax rate and available cost reduction opportunities. We are interested in examining how the company's cost management strategy differs under alternative regulatory systems.

Reference Regulatory Systems[195]

We have developed five "reference" regulatory systems that constitute useful comparators for MRPs:

One is "cost plus" regulation, in which a company's revenue is exactly equal to its cost every year. This has no real-world counterpart, since even traditional regulation requires at least a one-year rate case cycle and some incentive, once rates are set, to cut costs of base rate inputs. Another reference system is full externalization of the ratemaking process so that rates are no longer trued up periodically to the company's costs. Such an outcome would be obtained if the company were to embark on a permanent revenue cap regime.

The other three reference regimes approximate traditional regulation. In each, there is a predictable cycle of rate cases in which revenue is reset to the company's cost. We consider cycles of one, two and three years.

Multiyear Rate Plans

We considered various types of MRPs in our incentive power research. In most of these plans, there is no stretch factor shaving the revenue requirement mechanistically from year to year. The plans differ with respect to several kinds of provisions:

- *Plan term.* We consider terms of three, five, six and 10 years.

- *Impact of earnings sharing.* Plans considered also vary with respect to the earnings sharing specification. We consider earnings sharing mechanisms that have various company/customer allocations of earnings variances. Company shares considered are zero, 25 percent, 50 percent and 75 percent. None of the mechanisms considered have dead bands or multiple sharing bands, as these complicate calculations.

- *How rates change with rate case.* Our characterization of the rate case is important in modeling both traditional regulation and the MRP regimes. We assume in most model runs that rates in the initial year of the new regulatory cycle are, with one qualification, set to reflect the cost of service in the last year of the previous regulatory cycle.[196] The qualification is that any upfront *accountable* costs of initiatives for sustainable cost reductions that are undertaken in the historical reference year are amortized over the term of the plan.

- *Efficiency carryover mechanisms.* We also have considered the impact of some stylized efficiency carryover mechanisms. In one mechanism, the revenue requirement at the start of a new plan is based on a percentage (α%) of the cost in the last year of the previous plan and (1-

[195] The tables presented later in this appendix present results for these various scenarios.
[196] This is reasonable considering the lack of inflation and the stability of demand.

α)% on the revenue requirement in that year. This effectively permits the company to share (1-α)% any deviation between its cost and the revenue requirement. We consider alternative values of α, ranging from 90 percent to 50 percent.

In addition, we considered an efficiency carryover mechanism in which the revenue requirement in the first year of a new rate plan is adjusted for a percentage of the variance between an exogenous benchmark value of cost in the last plan year and the actual cost incurred. The revenue requirement for the first year of the new MRP is thus a weighted average of the benchmark and actual cost. The same result can be achieved by positing that the revenue requirement in year t is based 50/50 on the cost and the benchmark in year t-1.

- *Avoided rate case option.* We also have considered a menu approach to incenting long-term efficiency gains. It gives the company the option at the end of the plan to start the new plan without a rate case. The revenue requirement for the next plan is in this eventuality established on the basis of a predetermined formula. The formula we consider is a stretch factor reduction in the revenue requirement established in the preceding rate case.[197] The company can thus avoid a rate case if it agrees to a starting revenue requirement for the new plan that regulators believe offers value to customers.

Another decision that must be made in comparing alternative regulatory systems is what occurs at the conclusion of a plan. Our view is that the best way to compare the merits of alternative systems is to have them repeat themselves numerous times. For example, we examine the incentive impact of five-year plan terms by examining the cost containment strategy of a company faced with the prospect of a lengthy series of five-year plans.

Identifying the Optimal Strategy

Numerical analysis was used to predict the utility's optimal strategy. Under this approach we considered, for each regulatory system and each kind of cost containment initiative, thousands of different possible responses by the company. We chose as the predicted strategy the one yielding the highest value for the utility's objective function. An advantage of numerical analysis in this application is that it permits us to consider regulatory systems of considerable realism.

Research Results

Tables B-1 to B-3 present a summary of results from the incentive power model. For each of several regulatory systems the tables show the net present value of cost reductions from the operation of the system over many years. In the columns on the right-hand side of the tables, we report the average percentage reduction in the company's total cost that results from the regulatory system. We report outcomes for the first and second plan and the long run. We discuss here only the long-run results.

Results are presented for 10 percent, 30 percent and 50 percent levels of initial operating inefficiency. We focus here on the 30 percent results since our benchmarking research over the years has suggested that this is a normal level of operating inefficiency. Table B-1 presents the 30 percent results. Tables B-2 and B-3 show that performance gains from more incentivized regulatory systems are generally larger for less efficient companies. Changes in productivity from the various PBR mechanisms are greatest in Table B-3 (companies starting with 50 percent inefficiency) and smallest in Table B-2 (companies starting with 10 percent inefficiency).

[197] In a world of input price and output growth, a more complex formula would be required.

Results for Reference Regulatory Systems

Table B-1 shows that no cost reduction initiatives are undertaken under cost plus regulation. This reflects the fact that there is no monetary reward for undertaking cost reduction initiatives, all of which involve unaccountable costs. At the other extreme, a complete externalization of future rates such as might occur if rate cases were never held again produces performance improvements relative to cost plus regulation that, over many years, accumulate to a net present value (NPV) of more than $2 billion. Average annual performance gains of 2.71 percent (or 271 basis points) are achievable in the long run.

As for the traditional regulatory systems, the system with a *three*-year cycle incents companies to achieve long-run savings with an NPV of about $900 million — a major improvement over cost plus regulation but less than half of the savings that are potentially available from efficiency initiatives. Average annual performance gains rise from zero to 0.90 percent. The fact that some cost savings occur under traditional regulation is not surprising inasmuch as the assumed three-year regulatory cycle permits some gains to be reaped from temporary cost reduction opportunities and from projects with one-year payback periods. A two-year rate case cycle produces only 0.66 percent annual performance gains.

Table B- 1 Results From the Incentive Power Model: 30% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	657	**29%**	1.19%	0.66%
3 Year Cost of Service	899	**39%**	1.22%	0.90%
Full Rate Externalization	2299	**100%**	3.93%	2.71%
Impact of Plan Term				
Term = 3 years	899	**39%**	1.22%	0.90%
Term = 5 years	1318	**57%**	1.93%	1.41%
Term = 6 years	1428	**62%**	1.96%	1.58%
Term = 10 years	1664	**72%**	2.35%	2.23%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1318	**57%**	1.93%	1.41%
Company Share = 75%	1075	**47%**	1.29%	1.17%
Company Share = 50%	966	**42%**	1.14%	1.01%
Company Share = 25%	879	**38%**	1.03%	0.88%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	990	**43%**	1.29%	1.07%
Externalized Percentage = 25%	1336	**58%**	1.80%	1.66%
Externalized Percentage = 50%	1799	**78%**	3.41%	2.15%
5-Year Plans, Extern				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1469	**64%**	2.07%	1.55%
Externalized Percentage = 25%	1598	**70%**	2.30%	1.76%
Externalized Percentage = 50%	1989	**86%**	3.00%	2.27%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	1535	**67%**	2.26%	1.93%
Externalized Percentage = 25%	1824	**79%**	3.68%	2.29%
Externalized Percentage = 50%	2016	**88%**	3.84%	2.54%
5-Year Plans				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1621	**70%**	2.34%	1.80%
Externalized Percentage = 25%	1908	**83%**	3.08%	2.31%
Externalized Percentage = 50%	2109	**92%**	3.57%	2.56%
Rate Option Plans				
3-Year Plans				
No rate option	899	**39%**	1.93%	0.90%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2.5%	899	**39%**	1.93%	0.90%
5-Year Plans				
No rate option	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 2.5%	1318	**57%**	1.93%	1.41%

*** = measured by the average year-over-year percent decrease in costs**

Table B-2 Results From the Incentive Power Model: 10% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	436	**29%**	1.08%	0.57%
3 Year Cost of Service	623	**42%**	1.02%	0.76%
Full Rate Externalization	1496	**100%**	2.64%	2.32%
Impact of Plan Term				
Term = 3 years	623	**42%**	1.02%	0.76%
Term = 5 years	811	**54%**	1.10%	1.15%
Term = 6 years	976	**65%**	1.19%	1.30%
Term = 10 years	1088	**73%**	1.48%	1.73%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	811	**54%**	1.10%	1.15%
Company Share = 75%	723	**48%**	0.97%	0.97%
Company Share = 50%	653	**44%**	0.87%	0.84%
Company Share = 25%	602	**40%**	0.83%	0.73%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	672	**45%**	1.09%	0.87%
Externalized Percentage = 25%	887	**59%**	1.32%	1.36%
Externalized Percentage = 50%	1123	**75%**	1.87%	1.80%
5-Year Plans, Extern				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	932	**62%**	1.20%	1.27%
Externalized Percentage = 25%	1025	**69%**	1.36%	1.47%
Externalized Percentage = 50%	1239	**83%**	1.91%	1.90%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	1037	**69%**	1.65%	1.64%
Externalized Percentage = 25%	1182	**79%**	2.08%	1.94%
Externalized Percentage = 50%	1253	**84%**	2.48%	2.16%
5-Year Plans				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	1033	**69%**	1.42%	1.42%
Externalized Percentage = 25%	1229	**82%**	1.97%	1.83%
Externalized Percentage = 50%	1280	**86%**	2.41%	2.26%
Rate Option Plans				
3-Year Plans				
No rate option	623	**42%**	1.02%	0.76%
Yearly rate reduction = 1%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	623	**42%**	1.02%	0.76%
Yearly rate reduction = 2.5%	623	**42%**	1.02%	0.76%
5-Year Plans				
No rate option	811	**54%**	1.10%	1.15%
Yearly rate reduction = 1%	1496	**100%**	2.64%	2.32%
Yearly rate reduction = 1.5%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2.5%	811	**54%**	1.10%	1.15%

*** = measured by the average year-over-year percent decrease in costs**

Table B-3. Results From the Incentive Power Model: 50% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	905	**30%**	1.33%	0.75%
3 Year Cost of Service	1430	**47%**	2.36%	1.05%
Full Rate Externalization	3022	**100%**	4.75%	3.05%
Impact of Plan Term				
Term = 3 years	1430	**47%**	2.36%	1.05%
Term = 5 years	1778	**59%**	2.29%	1.65%
Term = 6 years	2143	**71%**	2.37%	1.82%
Term = 10 years	2520	**83%**	3.29%	2.42%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1778	**59%**	2.29%	1.65%
Company Share = 75%	1603	**53%**	2.06%	1.36%
Company Share = 50%	1520	**50%**	1.96%	1.22%
Company Share = 25%	1354	**45%**	1.75%	1.02%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	1551	**51%**	2.48%	1.21%
Externalized Percentage = 25%	2017	**67%**	3.17%	1.90%
Externalized Percentage = 50%	2481	**82%**	4.08%	2.42%
5-Year Plans, Extern				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	1979	**65%**	2.52%	1.81%
Externalized Percentage = 25%	2279	**75%**	2.75%	2.02%
Externalized Percentage = 50%	2666	**88%**	3.68%	2.60%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	2202	**73%**	3.58%	2.20%
Externalized Percentage = 25%	2531	**84%**	4.30%	2.61%
Externalized Percentage = 50%	2793	**92%**	4.61%	2.84%
5-Year Plans				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	2309	**76%**	2.81%	2.04%
Externalized Percentage = 25%	2558	**85%**	3.68%	2.54%
Externalized Percentage = 50%	2880	**95%**	4.35%	2.88%
Rate Option Plans				
3-Year Plans				
No rate option	1430	**47%**	2.36%	1.05%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	3022	**100%**	4.75%	3.05%
5-Year Plans				
No rate option	1778	**59%**	2.29%	1.65%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	1778	**59%**	2.29%	1.65%

*** = measured by the average year-over-year percent decrease in costs**

Impact of Plan Term

Consider now the effect of extending the plan term beyond the conventional three-year rate case cycle. Extending the term from three years to five years increases annual performance gains by about 51 basis points in the long run. Evidently, stronger performance incentives elicit better performance. Extending the term from three years to 10 years increases average annual performance gains by 133 basis points.

The benefits of a longer plan term are greater when rate cases would be more frequent under traditional regulation. For example, if rate cases would otherwise be held every two years, a five-year MRP with no earnings sharing produces 75 basis points of additional annual performance gains in the long run.

Impact of Earnings Sharing

The third panel of Table B-1 shows that the addition of earnings sharing mechanisms (ESMs) reduces cost savings compared to a plan of the same duration with no sharing mechanism. For example, a five-year plan in which the company keeps 75 percent of earnings variances produces only 27 basis points of additional performance gains annually in the long run compared to a three-year rate case cycle.

However, plans with an earnings sharing mechanism can deliver more cost savings than a pattern of frequent rate cases. For example, a five-year plan with 75/25 sharing produces 51 more basis points of annual performance gains than traditional regulation with a two-year cycle.

Impact of Efficiency Carryover Mechanism

Let's consider now the impact of the efficiency carryover mechanism that uses the predetermined revenue requirement from the previous plan as the benchmark. The fourth panel of Table B-1 shows that, in the context of a five-year rate plan, assigning the benchmark a weight of 25 percent produces 35 basis points of additional performance gains. Of greater interest perhaps is that it boosts the performance gains from a three-year plan by a substantial 76 basis points. Thus, this efficiency carryover mechanism can give a three-year plan considerable incentive power.

Let's turn now to the alternative efficiency carryover mechanism approach in which cost in the historical reference year is compared to a *fully external* benchmark such as that produced by an econometric model developed using industry data. Remarkably, the fifth panel of Table B-1 shows that assigning the benchmark a weight of only 25 percent more than doubles the cost savings produced by three-year plans. This suggests that a benchmark-based efficiency carryover mechanism has the potential to strengthen performance incentives rather dramatically. With a *five*-year rate case cycle, the effect of the same 25 percent externalization is still substantial, but more modest than in a three-year cycle. This is mainly due to the fact that more of the potential cost savings are achieved by the five-year term.

Impact of Rate Case Avoidance

Let's turn now to the impact of rate case avoidance. The sixth panel of Table B-1 shows that, in three-year plans with stretch factors of 1 percent, 1.5 percent and 2 percent, this approach produces the same dramatic cost efficiency savings that would result from full rate externalization. Evidently, the company judges that with a high level of cost containment effort it can get its costs permanently below the cost growth target and acts accordingly.

Conclusions

Our incentive power research for this report yields important results on the consequences of alternative regulatory systems. Most fundamentally, the results show that the frequency of rate cases can have a material impact on utility cost performance. Under COSR, performance will be considerably better when rate cases typically occur every three years than when they typically occur every two years. Thus, the favorability of business conditions affects operating performance.

Our research also shows that an MRP with a five-year rate case cycle can simulate the stronger incentives, especially when rate cases are more frequent than every three years. In addition, an MRP should have advantages when the alternative is pervasive cost trackers. Incentives are weakened under an ESM. We also show that adding innovative plan provisions on the frontier of PBR, such as efficiency carryover mechanisms and menus, can materially strengthen performance incentives. Many of the real-world plans reviewed in this report did not have these incentive power "turbochargers."

B.2 Utility Productivity Research

We presented results of our utility productivity research in Section 6 of this report. This section of Appendix B discusses productivity and revenue cap indexes, sources of productivity growth, and productivity trends of U.S. power distributors. We also provide mathematical details of the calculations.

Productivity Indexes

The Basic Idea

A productivity index is the ratio of an output quantity index (Outputs) to an input quantity index (Inputs):

$$Productivity = \frac{Outputs}{Inputs} \qquad [B1]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. The growth trend of a productivity trend index can then be shown mathematically to be the *difference* between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Outputs - trend\ Inputs. \qquad [B2]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but tends to grow over time. The volatility is typically due to fluctuations in output, the uneven timing of certain expenditures, or both. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A *multifactor* productivity index measures productivity in the use of multiple inputs.

The output (quantity) index of a firm or industry summarizes trends in the scale of operation. Growth in each output dimension that is itemized is measured by a subindex. One possible objective of output research is to measure the impact of output growth on company *cost.* In that case, the sub-indexes should measure the dimensions of the "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers.[198] A productivity index calculated using a cost-based output index may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are a second source of productivity growth. These economies are available in the longer run if cost tends to grow more slowly than output. A company's potential to achieve incremental scale economies depends on the pace of its output growth. Incremental scale economies (and thus productivity growth) will typically be reduced when output growth slows.

A third important source of productivity growth is change in inefficiency. Inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth rises (falls) when inefficiency diminishes (increases). The lower the company's current efficiency level, the greater the potential for productivity growth from a change in inefficiency.

Another driver of productivity growth is changes in the miscellaneous external business conditions, other than input price inflation and output growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. An increase in the share of lines that are undergrounded will tend to slow multifactor productivity growth (because of the higher capital requirements) but accelerate O&M productivity growth (since there is less line maintenance).

Finally, consider that in the short to medium run a utility's productivity growth is driven by the position of the utility in the cycle of asset replacement. Productivity growth will be slower to the extent that the need for replacement capex is large relative to the existing stock of capital.

Revenue Cap Indexes

Index research provides the basis for revenue cap indexes. The following basic result of cost research is a useful starting point:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity} + \textit{growth Outputs} \qquad \text{[B3]}$$

The cost trend is the difference between the trends in input price and productivity indexes plus the trend in operating scale as measured by a cost-based output index. This result provides the rationale for a revenue cap escalator of the following general form:

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Outputs} \qquad \text{[B4a]}$$

where

$$X = \overline{MFP} + \textit{Stretch}. \qquad \text{[B4b]}$$

[198] The sensitivity of cost to the change in a business condition variable is commonly measured by its cost "elasticity." Elasticities can be estimated econometrically using data on the operations of a group of utilities. A multiple category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver.

Here X, the "X factor," is calibrated to reflect a base MFP growth target ($\overline{MFP}$). A "stretch factor" is often added to the formula which slows revenue cap index growth in a manner that shares with customers the financial benefits of performance improvements expected during the MRP. Since the X factor often includes *Stretch,* it is sometimes said that the index research has the goal of "calibrating" (rather than solely determining) X.

For electric power distributors, the number of customers served is a useful scale variable for a revenue cap index. Relation [B3] can then be restated as:

$$\begin{aligned} &\textit{trend Cost} \\ &\quad = \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\ &\quad = \textit{trend Input Prices} - \textit{trend } MFP^N + \textit{trend Customers} \qquad \text{[B5a]} \end{aligned}$$

where MFP^N is an MFP index that uses the number of customers to measure output.

Rearranging the terms of [B5a] we obtain:

$$\begin{aligned} &\textit{trend Cost} - \textit{trend Customers} \\ &= \textit{trend } (\textit{Cost/Customer}) = \textit{trend Input Prices} - \textit{trend } MFP^N. \qquad \text{[B5b]} \end{aligned}$$

This provides the basis for the following revenue per customer index formula:[199]

$$\textit{growth Revenue/Customer} = \textit{growth Input Prices} - X + Y + Z \qquad \text{[B6]}$$

where

$$X = \overline{MFP^N} + \textit{Stretch}.$$

Productivity Trends of U.S. Power Distributors

<u>Data</u>

The primary source of our cost and quantity data is FERC Form 1. Selected Form 1 data were for many years published by the U.S. Energy Information Administration (EIA).[200] More recently, the data have been available electronically in raw form from FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained directly from government agencies and processed by PEG Research. Customer data were drawn from FERC Form 1 in the early years of the sample period and from Form EIA-861 (the *Annual Electric Power Industry Report)* in later years.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the United States that filed the Form 1 in 1964 (the benchmark year for our study, described further below)

[199] This general formula for the design of revenue cap indexes is currently used in the PBR plans of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Gaz Métro to develop a plan featuring revenue per customer indexes. Revenue per customer indexes were previously used by Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the United States and Canada, respectively.
[200] This publication series had several titles over the years. A recent title is Financial Statistics of Major US Investor-Owned Electric Utilities.

and that, together with any important predecessor companies, have reported the necessary data continuously. To be included in the study the data also were required to be of good quality and plausible. One important quality criterion was that there were no major shifts in cost between the distribution and transmission plant. Data from 86 utilities met our standards and were used in our indexing work. We believe that these data are the best available for rigorous work on the productivity trends of U.S. power distributors.

Table B-4 lists the companies from which data were drawn. Most broad regions of the United States are well-represented.[201]

Scope of Research

The total cost of power distributor services considered in the study was the sum of applicable O&M expenses and capital costs. Reported costs of any gas services provided by combined gas and electric utilities in the sample were excluded.[202] We also excluded expenses for purchased power and customer service and information. The featured results employed a geometric decay approach to capital cost measurement that is explained further below. Capital cost is the sum of depreciation expenses, a return on the value of net plant, taxes and capital gains.

We calculated indexes of growth in the O&M, capital, and multifactor productivity of each sampled utility in the provision of power distributor services. Simple arithmetic averages of those growth rates were then calculated for all sampled companies.

[201] Unfortunately, the requisite customer data are not available for most Texas distributors.
[202] Gas service costs of combined gas and electric utilities are itemized on FERC Form 1 for easy removal. We exclude customer service and information expenses because on FERC Form 1 these include DSM expenses.

Table B-4. Companies Included in Our Power Distributor Productivity Research

Alabama Power
ALLETE (Minnesota Power)
Appalachian Power
Arizona Public Service
Atlantic City Electric
Avista
Baltimore Gas and Electric
Central Hudson Gas & Electric
Central Maine Power
Cleco Power
Cleveland Electric Illuminating
Connecticut Light and Power
Consolidated Edison
Dayton Power and Light
Delmarva Power & Light
Duke Energy Carolinas
Duke Energy Florida
Duke Energy Indiana
Duke Energy Kentucky
Duke Energy Ohio
Duke Energy Progress
Duquesne Light
El Paso Electric
Empire District Electric
Entergy Louisiana
Entergy Mississippi
Entergy New Orleans
Fitchburg Gas and Electric Light
Florida Power & Light
Georgia Power
Green Mountain Power
Gulf Power
Idaho Power
Indiana Michigan Power
Indianapolis Power & Light
Jersey Central Power & Light
Kansas City Power & Light
Kansas Gas and Electric
Kentucky Power
Kentucky Utilities
Kingsport Power
Louisville Gas and Electric
Massachusetts Electric
MDU Resources Group
Metropolitan Edison
MidAmerican Energy
Mississippi Power
Monongahela Power
Narragansett Electric
Nevada Power
New York State Electric & Gas
Niagara Mohawk Power
Northern States Power - MN
Northwestern Public Service
Nstar Electric
Ohio Edison
Ohio Power
Oklahoma Gas and Electric
Orange and Rockland Utilities
Otter Tail Power
Pacific Gas and Electric
PacifiCorp
PECO Energy
Pennsylvania Electric
Pennsylvania Power
Portland General Electric
Public Service Company of Colorado
Public Service Company of Oklahoma
Public Service Electric and Gas
Rochester Gas and Electric
San Diego Gas & Electric
South Carolina Electric & Gas
Southern California Edison
Southern Indiana Gas and Electric
Superior Water, Light and Power
Tampa Electric
Toledo Edison
Union Electric
United Illuminating
Virginia Electric and Power
West Penn Power
Western Massachusetts Electric
Wheeling Power
Wisconsin Electric Power
Wisconsin Power and Light
Wisconsin Public Service

Number of Sampled Companies: 86

The major tasks in a power distributor's operation are the local delivery of power and the reduction of its voltage. Most power is delivered to end users at the voltage at which it is consumed. U.S. distributors also typically provide an array of customer services such as metering and billing.

Index Construction

Productivity growth was calculated for each sampled utility as the difference between the growth rates of output and input quantity trends. We used as a proxy for output growth the growth in the total number of retail customers served.

In calculating input quantity trends, we broke down the applicable cost into those for distribution plant, general plant, labor, and material and service (M&S) inputs. The cost of labor was defined for this purpose as O&M salaries and wages and pensions and other benefits. The cost of M&S inputs was defined as applicable O&M expenses net of these labor costs. The growth of the multifactor input quantity index is a weighted average of the growth in quantity subindexes for labor, materials and services, and power distribution plant.

Sample Period

The full sample period for which productivity results were calculated was 1980-2014.[203]

Index Results

Table B-5 summarizes our productivity research for the full sample. Over the full 1980-2014 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors was about 0.45 percent. Customer growth averaged 1.16 percent annually, whereas input growth averaged 0.70 percent. O&M productivity growth averaged 0.53 percent while capital productivity growth averaged 0.43 percent. O&M productivity growth was much more volatile than capital productivity growth.

[203] In other words, 1980 was the earliest year for growth rate calculations.

Table B-5. U.S. Power Distribution Productivity Trends

	Output	Inputs	PFP O&M	PFP Capital	MFP
1980	1.77%	2.26%	-4.19%	1.24%	-0.49%
1981	1.66%	1.49%	-2.42%	1.25%	0.17%
1982	1.63%	0.76%	-1.20%	1.53%	0.87%
1983	0.96%	0.45%	-0.38%	0.98%	0.51%
1984	1.60%	0.33%	-0.22%	1.79%	1.27%
1985	1.71%	0.76%	-0.21%	1.37%	0.95%
1986	1.70%	0.79%	0.88%	0.97%	0.91%
1987	1.77%	1.33%	-0.12%	0.68%	0.44%
1988	1.47%	0.90%	1.55%	0.24%	0.57%
1989	1.49%	1.23%	0.00%	0.23%	0.26%
1990	1.42%	1.25%	0.64%	-0.05%	0.18%
1991	1.17%	1.20%	0.58%	-0.32%	-0.03%
1992	1.12%	0.64%	1.61%	0.10%	0.48%
1993	1.41%	0.96%	1.19%	0.12%	0.45%
1994	1.39%	0.45%	2.44%	0.29%	0.94%
1995	1.40%	0.46%	3.58%	-0.04%	0.94%
1996	1.16%	1.05%	0.67%	-0.13%	0.11%
1997	1.37%	-0.16%	4.68%	0.39%	1.53%
1998	1.54%	0.87%	0.73%	0.71%	0.67%
1999	0.81%	-0.27%	2.24%	0.52%	1.08%
2000	1.37%	0.48%	0.86%	0.73%	0.89%
2001	1.59%	0.39%	2.73%	0.61%	1.20%
2002	1.17%	0.38%	2.73%	0.33%	0.79%
2003	1.14%	1.17%	-1.50%	0.43%	-0.03%
2004	1.06%	0.66%	0.76%	0.22%	0.41%
2005	1.07%	1.14%	-0.25%	0.09%	-0.07%
2006	0.51%	1.03%	-1.07%	-0.21%	-0.52%
2007	1.02%	1.14%	0.00%	-0.02%	-0.12%
2008	0.54%	1.53%	-2.06%	-0.09%	-0.99%
2009	0.26%	-0.75%	2.73%	-0.46%	1.01%
2010	0.45%	0.72%	-0.47%	0.05%	-0.27%
2011	0.28%	-0.22%	0.05%	0.50%	0.50%
2012	0.39%	-0.91%	2.90%	0.58%	1.29%
2013	0.44%	0.41%	0.40%	-0.05%	0.03%
2014	0.65%	0.68%	-1.41%	0.56%	-0.03%
Average Annual Growth Rates					
1980-2014	**1.16%**	**0.70%**	**0.53%**	**0.43%**	**0.45%**
1996-2014	**0.88%**	**0.49%**	**0.77%**	**0.25%**	**0.39%**
2008-2014	**0.43%**	**0.21%**	**0.30%**	**0.15%**	**0.22%**

Over the more recent 1996-2014 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors was similar, at 0.39 percent. Customer growth slowed modestly to average 0.88 percent annually, while input growth averaged 0.49 percent annually. O&M productivity growth accelerated to average 0.77 percent, while capital productivity growth slowed to average 0.25 percent.

Since 2007 the MFP growth of power distributors has slowed modestly, averaging 0.22 percent annually. This is mainly due to a slowdown in O&M productivity growth, which averaged 0.30 percent annually. Capital productivity growth slowed slightly to average 0.15 percent.

Table B-6 provides the annual growth rates in the MFP indexes for the individual utilities in our sample. We report results for the full sample period (1980-2014) and for the 1996-2014 and 2008-2014 sample periods.

<u>Additional Details on Productivity Research</u>

Input Quantity Indexes. The quantity subindex for labor is the ratio of salary and wage expenses to a regionalized salary and wage labor price index.[204] The quantity subindex for M&S inputs is the ratio of the expenses to the GDPPI. Details of the capital quantity index are provided below.

The summary quantity indexes for O&M, capital, and all inputs were of chain-weighted Törnqvist form.[205] This means that their annual growth rate was determined by the following general formula:

$$ln\left({Inputs_t}/{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot ln\left({X_{j,t}}/{X_{j,t-1}} \right) \qquad [B7]$$

where in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost

[204] The growth rate of the labor price index was calculated for most years as the growth rate of the national employment cost index (ECI) for the salaries and wages of the utility sector plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole.
[205] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

Table B-6. Power Distributor MFP Trends of Individual U.S. Electric Utilities

Distributor	Average Annual MFP Growth Rate 1980-2014	1996-2014	2008-2014
Alabama Power	-0.52%	-0.61%	-0.50%
ALLETE (Minnesota Power)	0.86%	1.32%	0.54%
Appalachian Power	0.12%	0.38%	-0.29%
Arizona Public Service	0.39%	0.88%	0.98%
Atlantic City Electric	0.37%	0.10%	-1.37%
Avista	0.41%	0.09%	-0.71%
Baltimore Gas and Electric	0.35%	-0.06%	-1.08%
Central Hudson Gas & Electric	0.81%	-0.04%	-0.45%
Central Maine Power	0.66%	0.79%	0.28%
Cleco Power	-0.14%	-0.35%	-0.42%
Cleveland Electric Illuminating	0.40%	0.49%	0.05%
Connecticut Light and Power	0.41%	-0.10%	0.03%
Consolidated Edison	0.06%	-0.45%	-0.44%
Dayton Power and Light	0.84%	0.35%	-0.93%
Delmarva Power & Light	0.60%	0.71%	-1.08%
Duke Energy Carolinas	-0.04%	1.09%	0.75%
Duke Energy Florida	0.64%	0.38%	1.00%
Duke Energy Indiana	0.58%	0.08%	-0.09%
Duke Energy Kentucky	0.35%	0.54%	-1.24%
Duke Energy Ohio	0.58%	0.81%	-0.87%
Duke Energy Progress	0.56%	0.65%	1.35%
Duquesne Light	0.64%	0.73%	0.04%
El Paso Electric	0.88%	0.45%	-0.17%
Empire District Electric	-0.09%	-0.26%	-0.65%
Entergy Louisiana	0.63%	0.71%	1.86%
Entergy Mississippi	-0.01%	-0.17%	0.40%
Entergy New Orleans	0.43%	-0.54%	4.37%
Fitchburg Gas and Electric Light	0.34%	0.22%	0.98%
Florida Power & Light	0.84%	0.66%	1.06%
Georgia Power	0.40%	1.11%	1.09%
Green Mountain Power	0.82%	0.52%	1.05%
Gulf Power	0.21%	0.28%	-0.39%
Idaho Power	1.29%	1.48%	1.23%
Indiana Michigan Power	0.30%	-0.02%	-0.46%
Indianapolis Power & Light	0.81%	1.17%	0.86%
Jersey Central Power & Light	0.68%	0.63%	0.84%
Kansas City Power & Light	1.01%	0.76%	0.37%
Kansas Gas and Electric	0.70%	0.57%	0.18%
Kentucky Power	-0.71%	-0.56%	-1.42%
Kentucky Utilities	0.18%	0.01%	-2.38%
Kingsport Power	0.46%	0.23%	-1.33%
Louisville Gas and Electric	0.33%	0.20%	-2.39%
Massachusetts Electric	0.96%	1.10%	0.72%
MDU Resources Group	0.61%	0.76%	1.01%
Metropolitan Edison	1.25%	1.42%	1.06%

Table B-6 (continued) Power Distributor MFP Trends of Individual U.S. Electric Utilities

Distributor	1980-2014	1996-2014	2008-2014
MidAmerican Energy	0.04%	1.22%	2.37%
Mississippi Power	-1.18%	-1.42%	0.65%
Monongahela Power	0.10%	0.57%	0.54%
Narragansett Electric	0.80%	0.57%	-0.03%
Nevada Power	0.99%	1.12%	1.67%
New York State Electric & Gas	1.02%	1.57%	1.51%
Niagara Mohawk Power	0.54%	0.81%	0.68%
Northern States Power - MN	0.73%	0.26%	1.06%
Northwestern Public Service	0.30%	0.68%	1.01%
Nstar Electric	0.40%	0.59%	1.14%
Ohio Edison	0.97%	1.34%	1.02%
Ohio Power	0.28%	0.45%	-0.20%
Oklahoma Gas and Electric	0.14%	-0.07%	-0.49%
Orange and Rockland Utilities	0.82%	0.32%	0.07%
Otter Tail Power	0.00%	0.04%	0.37%
Pacific Gas and Electric	0.24%	-0.04%	0.10%
PacifiCorp	0.08%	1.18%	2.26%
PECO Energy	0.91%	0.16%	-0.21%
Pennsylvania Electric	0.84%	0.94%	1.15%
Pennsylvania Power	0.60%	0.75%	0.51%
Portland General Electric	0.57%	-0.72%	0.10%
Public Service Company of Colorado	0.72%	0.01%	0.90%
Public Service Company of Oklahoma	0.00%	-0.43%	0.07%
Public Service Electric and Gas	0.80%	0.76%	0.49%
Rochester Gas and Electric	1.05%	0.64%	0.97%
San Diego Gas & Electric	-0.31%	-0.41%	0.21%
South Carolina Electric & Gas	0.16%	0.21%	0.02%
Southern California Edison	-0.08%	-0.45%	-1.47%
Southern Indiana Gas and Electric	0.29%	-0.03%	-1.19%
Superior Water, Light and Power	0.57%	0.31%	-0.40%
Tampa Electric	0.97%	0.80%	0.42%
Toledo Edison	1.07%	1.13%	0.94%
Union Electric	0.38%	0.25%	0.45%
United Illuminating	-0.72%	-1.51%	-5.50%
Virginia Electric and Power	0.65%	0.88%	0.64%
West Penn Power	0.83%	1.38%	1.73%
Western Massachusetts Electric	0.75%	1.01%	0.42%
Wheeling Power	0.11%	-0.19%	-1.06%
Wisconsin Electric Power	0.41%	0.11%	0.74%
Wisconsin Power and Light	-0.04%	-0.29%	-0.38%
Wisconsin Public Service	0.82%	0.57%	2.31%
Full Sample Averages	**0.45%**	**0.39%**	**0.22%**

The growth rate of each summary index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable total cost of each utility in the current and prior years served as weights.

Productivity Growth Rates and Trends. The annual growth rate in each company's productivity index is given by the formula:

$$ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right)$$
$$= ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right) \qquad [B8]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Capital Cost Measurement. A service price approach is used to measure capital costs. This approach has a solid basis in economic theory and is widely used in scholarly empirical work. In the application of the general method used in this study, the cost of a given class of utility plant j in a given year t ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year ($XK_{j,\,t-1}$):

$$CK_{j,t} = WKS_{j,t} \bullet XK_{j,\,t-1} \qquad [B9a]$$

It can then be shown mathematically that:

$$growth\ CK_{j,t} = growth\ WKS_{j,t} + growth\ XK_{j,\,t-1} \qquad [B9b]$$

In constructing both indexes we used the geometric decay approach. We took 1964 as the benchmark year. The values for these indexes in the benchmark year are based on the net value of plant as reported in FERC Form 1. We estimated the benchmark year (inflation-adjusted) value of net distribution plant by dividing this book value by a triangularized weighted average of 37 values of an index of utility construction cost for a period ending in the benchmark year.[206] The construction cost index (WKA_t) was the applicable regional Handy-Whitman index of the cost of the relevant asset category.[207]

The following formula was used to compute subsequent values of each capital quantity index:

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [B10]$$

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant. The economic depreciation rate was set at 4.34 percent for distribution plant. It is based on a weighted average of economic depreciation rates for different types of distribution assets. The depreciation rate also reflects declining balance parameters that were 0.91 for structures and 1.65 for equipment.

[206] A triangularized weighted average places a greater weight on more recent values of the construction cost index. This make sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.
[207] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

Following is the full formula for the capital service price indexes for each asset category:

$$WKS_{j,t} = [CK_{j,t}^{Taxes} / XK_{j,t-1}] + d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{\left(WKA_{j,t} - WKA_{j,t-1}\right)}{WKA_{j,t-1}}\right]. \quad \text{[B11]}$$

The first term in the expression corresponds to the cost of taxes and utility franchise fees ($CK_{j,t}^{Taxes}$). The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

The calculation of [B11] requires an estimate of the rate of return on capital (r_t). We employed a weighted average of rates of return for debt and equity.[208] Prior to 1995, we relied on a 50/50 average of the average yield on AA utility bonds and ROE using data from Moody's.[209] For subsequent years, we relied on a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data and the average allowed rate of ROE approved in electric utility rate cases for each year as reported by the Edison Electric Institute.[210]

B.3 Statistical Benchmarking

Quantitative performance benchmarking commonly involves one or more gauges of activity. These are sometimes called *key performance indicators* (KPIs) or *metrics.* The values of these indicators for a utility are compared to benchmark values that reflect performance standards. Given information on the cost of a utility and a certain cost benchmark one might, for instance, measure its cost performance by taking the ratio of the two values:

$$Cost\ Performance = Cost^{Actual} / Cost^{Benchmark}.$$

Benchmarks are often developed using data on the operations of agents that are involved in the activity under study. Statistical methods are useful in the calculation of benchmarks and are sometimes used in performance appraisals. An approach to benchmarking that features statistical methods is called *statistical benchmarking.*

Econometric Benchmarking

Cost benchmarks should reflect the cost pressures a utility faces. The impact of external business conditions on the costs of utilities can be estimated using statistics. Consider, by way of example, the following simple model of power distributor cost. In a given year t, the cost of power distributor h ($C_{h,t}$) is a function of the number of customers it serves ($N_{h,t}$) and the market wage rate ($W_{h,t}$):

$$C_{h,t} = a_0 + a_1 N_{h,t} + a_2 W_{h,t} \quad \text{[B12]}$$

The parameters a_1 and a_2 determine the impact of the business conditions on cost.

208 This calculation was made solely for the purpose of measuring productivity trends and does not prescribe appropriate rate of return levels for utilities.
209 Moody's Public Utility Manual (1995).
210 Edison Electric Institute.

A branch of statistics called *econometrics* has developed procedures for estimating the parameters of economic functions using historical data.[211] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions that they faced. Abundant, high quality data are available for this purpose from the federal government. The sample used in model estimation is typically a “panel” data set that pools time series data for several companies.

Tests can be constructed for the hypothesis that the parameter for a candidate cost driver equals zero. A variable is deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

A cost function fitted with econometric parameter estimates may be called an *econometric cost model*. We can use such a model to predict a company’s cost given local values for cost driver variables. These predictions are econometric benchmarks. Cost performance can be measured by comparing a company’s cost in year *t* to the cost projected for that year and company by the econometric model. There is no need to choose a peer group because the methodology uses the exact business conditions faced by the benchmarked company.

Suppose, for example, that we wish to benchmark the cost of a hypothetical utility called Eastern Edison. We might then predict the cost of Eastern Edison in period *t* using the following model constructed from [B12]:

$$\hat{C}_{Eastern,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Eastern,t} + \hat{a}_2 \cdot W_{Eastern,t} \ . \qquad [B13]$$

Here $\hat{C}_{Eastern,t}$ denotes the predicted cost of the company, $N_{Eastern,t}$ is the number of customers it served, and $W_{Eastern,t}$ measures the wage rate in its region. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula such as

$$Performance = C_{Eastern,t} / \hat{C}_{Eastern,t} \ .$$

Table B-7 provides details of the econometric model of total power distributor cost that is used to set stretch factors in the IRM4 multiyear rate plan in Ontario. There is one input price variable (a capital price index), three scale variables (the number of customers, the retail delivery volume, and peak demand), two additional business conditions (average line length and a system age variable), and a trend variable. Note that the number of customers is the scale variable with the highest parameter estimate and t statistic. This model has a translogarithmic functional form so that, in addition to the “first order terms” representing the basic business condition variables, there are interaction and quadratic terms for the price and output variables. Model parameters were estimated using Ontario data

[211] The estimation of model parameters is sometimes called regression.

Table B-7. Econometric Cost Model for Ontario[212]

VARIABLE KEY

Input Price:	WK = Capital Price Index
Outputs:	N = Number of Customers
	C = System Capacity Peak Demand
	D = Retail Deliveries
Other Business Conditions:	L = Average Line Length (km)
	NG = % of 2012 Customers added in the last 10 years
	Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.6271	85.5530
N*	0.4444	8.0730
C*	0.1612	3.2140
D*	0.1047	3.4010
WKxWK*	0.1253	4.5320
NxN	-0.3776	-1.6160
CxC	0.1904	0.9340
DxD*	0.1646	2.1660
WKxN*	0.0536	3.4540
WKxC	0.0100	0.7200
WKxD	-0.0001	-0.0100
NxC	0.1415	0.7040
NxD	0.0674	0.6790
CxD*	-0.1990	-2.3070
L*	0.2853	13.9090
NG*	0.0165	2.4110
Trend*	0.0171	12.5700
Constant*	12.815	683.362
System Rbar-Squared	0.983	
Sample Period	2002-2012	
Number of Observations	802	

***Variable is significant at 95% confidence level**

[212] Kaufmann, Hovde, Kalfayan, and Rebane (2013), p. 58.

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