Incentive Regulation for the Transmission & Distributor Services of Hydro-Québec

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26 October 2015
Errata 2 February 2016

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1. Introduction

Power transmission and distributor ("T&D") services in Québec are provided by Hydro-Québec ("HQ") through its functionally separate business units Hydro-Québec Distribution ("HQD") and Hydro-Québec TransÉnergie ("HQT"). Article 48.1 of the Loi sur la Régie de l'Énergie requires incentive regulation, [aka performance-based regulation ("PBR")] for these services.[1] Incentive regulation must fulfill the following objectives.

- Continual improvement in performance and service quality
- Cost reduction that benefits both consumers and the utility
- Streamlining of the rate setting process

The Régie decided in D-2014-033 that an approach to incentive regulation which HQ proposed and which involved frequent rate cases did not meet the requirements of the law. A proceeding to consider alternative incentive regulation approaches began in June 2014. The Régie retained Elenchus Research Associates to prepare a white paper on incentive regulation precedents in other jurisdictions.[2] This paper focused chiefly on examples of incentive regulation in Alberta, Australia, Britain, Ontario, Norway, and New York. All of these jurisdictions use variations on the **multiyear rate plan** ("**MRP**") approach to incentive regulation.

In a 30 June 2015 decision, the Régie established a tentative three-phase schedule for a proceeding to develop incentive regulation plans for HQD and HQT. Phase 1 is expected to conclude in April 2016 and consider characteristics and objectives of operational incentive regulation mechanisms and the approaches to incentive regulation that are compatible with the law. Key concerns on which the Régie seeks input include the following.

- Types of incentive regulation that respond to special features of transmission and distribution
- Appropriate performance metrics

[1] Quebec National Assembly, 40th legislature, 1st session, Bill n°25 (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 June 24, 2013.
[2] Elenchus Research Associates, *Performance-Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions*. January 2015.

- How to ensure that performance gains are fairly divided

This phase will involve written evidence, data requests, and oral testimony. A possible Phase 2 would involve a multifactor productivity ("MFP") study. Parties would propose incentive regulation mechanisms in Phase 3.

Pacific Economics Group ("PEG") Research LLC is a leading North American consultancy in the incentive regulation field. We have been active in the field for more than twenty years. Our work has included dozens of projects in Canada. We have been retained by the Association Québécoise des Consommateurs Industriels d'Electricité and the Conseil de l'Industrie Forestière du Québec to prepare an independent report on Phase 1 issues. We consulted with other intervenors in the preparation of the report.

This is the report on our work. Section 2 will discuss the challenge of regulating electric utilities using traditional cost of service regulation.[3] Section 3 provides an introduction to the alternative MRP approach to regulation. The design of attrition relief mechanisms used in MRPs is discussed at length in Section 4. Additional topics in MRP design are discussed in Section 5. Section 6 reviews some background conditions that are appropriate in the design of incentive regulation mechanisms for T&D services in Québec. There follow recommendations on the design of mechanisms appropriate for HQT and HQD. Further information on MRP design is provided in the Appendix.

2. The Regulatory Challenge

2.1 Traditional Regulation

The traditional approach that commissions use to regulate retail rates of electric utilities in North America developed over decades. This regulatory system is called "cost of service" regulation because rates for each utility are designed to recover that utility's costs for providing service.

The chief means of adjusting rates under traditional regulation is the general rate case. In these litigated proceedings, the base "revenue requirement" reflects the normalized cost of service in a test year. The cost of service is calculated as the sum of electric operation and

[3] Challenges of MRP regulation are discussed in the following sections.

maintenance ("O&M") expenses, depreciation, taxes, and a return on the net (depreciated) value of utility investments (aka the rate base).

The entire cost of service can in principle be subject to a prudence review in each rate case. Regulators can consider in these reviews whether any component of cost is too high. Prudence reviews can be time-consuming and controversial since prudence is difficult to assess and the dollars at stake incentivize parties to argue their positions energetically. Another frequent source of rate case controversy is the target rate of return on the equity component of rate base.

Regulators use cost trackers to expedite recovery of some costs. Large, volatile costs like those for fuel and purchased power have traditionally been tracked. Tracking is further discussed in Section 5. The components of rates that address the less volatile costs of non-energy inputs like labor, materials, and capital are sometimes called "base rates," and are not typically tracked.[4]

To establish rates, the revenue requirement must be allocated across the utility's services. For each service, rates are then set to recover the assigned revenue requirement given assumed quantities of "billing determinants." Most base rate revenue is typically drawn from usage charges which vary with a customer's use of the system. For commercial and industrial customers, demand charges collect most base rate revenue. For residential customers, who often lack advanced metering infrastructure, base rate revenue is typically drawn chiefly from volumetric charges. The balance of residential revenue is typically drawn from fixed customer charges.

2.2 Regulatory Issues[5]

Regulatory Cost and its Consequences

Regulatory cost is an important and underappreciated consideration in choosing a regulatory system. In the case of traditional regulation, the overriding cost concern is general

[4] Base rate revenue is sometimes called "margin."
[5] This section draws on a discussion in Mark Newton Lowry and Tim Woolf, *Performance-Based Regulation in a High DER Future*, Lawrence Berkeley National Laboratory, 2015 (forthcoming).

rate cases since the entire cost of a utility must be reviewed and all rates must be reset.[6] Regulators understandably seek ways to contain regulatory cost. The pressure to do so increases to the extent that rate cases are frequent, numerous utilities are regulated, and rate case issues are controversial.

A number of tools can help to contain regulatory cost. Some traditional economy measures have undesirable side effects. For example, discouraging the practices that complicate regulation can limit a utility's operating flexibility. Limiting the utility's rate and service offerings, for instance, reduces the difficult chores of allocating the revenue requirement across services. Utilities for this reason typically have limited rate and service offerings, and do not change these offerings much from year to year. These restrictions on marketing flexibility are undesirable to the extent that customers have diverse and rapidly changing needs for utility services.

Another traditional measure for lowering regulatory cost is to limit detailed prudence reviews to issues that are especially controversial, such as poor responses to major storms. Lower profile but nonetheless important prudence issues, such as the need for accelerated replacement capex, may receive much less attention. Regulators can use cost trackers to address volatile or rapidly rising costs that could otherwise trigger frequent general rate cases. Both of these economy measures can weaken utility performance incentives, including the incentive to contain capital expenditures ("capex"), as we discuss below.

Incentive Issues

To understand the incentive issues under traditional regulation it may help to consider the performance incentives of firms in competitive markets. The market for corn, Québec's most important agricultural crop, is illustrative.[7] Corn prices are sufficient to provide producers *as a group* with a competitive rate of return *in the long run*. Returns of efficient producers vary from year to year and are not always compensatory. Prices are completely insensitive to the cost of *individual* producers. Farmers thus keep all of the incremental after-tax profit from their

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[6] Rate cases nonetheless have benefits which include the opportunity to review utility operations and provide feedback.
[7] http://www.stat.gouv.qc.ca/statistiques/agriculture/ta3-2012-2013.htm.

efforts to reduce their costs. This strengthens their cost containment incentives. Owning farmland or corn-producing and drying equipment is not a goal in itself, and many corn producers rent some of the acreage, equipment, and storage capacity they use.[8] Consumers benefit in the long run as industry productivity growth drives down the real price of corn. Note also that prices vary with the quality of corn, so that farmers are incented to make sure that their corn complies with established quality standards.

The incentives embedded in traditional regulation of electric utilities differ from those in competitive markets in two important respects. Incentives to contain cost are weaker to the extent that a utility's revenue tracks its own cost closely. Were its revenue to track its cost exactly, a utility could grow its earnings only by growing its rate base. The closeness with which cost tracks revenue under traditional regulation is greater to the extent that rate cases are frequent and trackers address a large share of cost. Cost containment incentives can be especially weak for tracked costs.

The Alberta Utility Commission discussed the incentive problem with traditional regulation in a letter announcing a generic proceeding to consider PBR for provincial energy distributors. These companies were filing frequent rate cases in a period of rapid regional economic growth.

> This initiative proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources… These conditions complicate the task for regulators who must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing. Traditional rate-base rate of return regulation provides few opportunities to create meaningful positive economic incentives which would benefit both the companies and the customers. The Commission is seeking a better way to carry out its mandate so that the legitimate expectations of the regulated utilities and of customers are respected.[9]

[8] Many profitable companies (e.g., Apple) in other unregulated industries outsource most of their production to third parties.

[9] Alberta Utilities Commission (2010), pages 1-2.

Conservation and demand management ("CDM") poses special incentive issues under traditional regulation. Consider first that CDM reduces revenue from usage charges. Since costs of non-energy inputs such as capital are largely fixed in the short run, increased reliance on CDM reduces utility earnings until base rates can be raised in the next rate case. This disincentive abates with more frequent rate cases.

A second incentive issue arises from the fact that CDM can reduce opportunities for utilities to grow rate base. The impact is greatest for assets, such as substations, the need for which is closely tied to load. This disincentive to facilitate CDM is offset to the degree that utilities can profit from slowing rate base growth. Under traditional regulation, utilities benefit from slowing rate base growth only between rate cases. Any resulting reduction in the depreciated value of rate base in the test year for the next rate case is passed entirely to customers. For example, the portion of the revenue requirement corresponding to an aging distribution substation that has not been replaced due in whole or part to CDM is reset in the next rate case to its lower, more depreciated value. The incentive to contain rate base growth thus falls with the frequency of rate cases and the pervasiveness of trackers for load-related capex costs.

Many other costs that are sensitive to CDM reliance are tracked, and this also weakens incentives to embrace CDM solutions. Most notable are the costs of energy commodities. For example, a reduction in the cost of purchased power that might result from energy efficiency programs results promptly in a commensurate revenue drop. Some utilities also have tracker treatment of transmission expenses.

We conclude that utilities under traditional regulation have a material disincentive to accommodate CDM even when CDM meets customer needs at lower cost than traditional grid service. Under traditional regulation utilities are, in other words, incented to oppose efficient levels of CDM.

Mandates Aren't Enough

Key aspects of utility behavior can and should be mandated. For example, regulators approve the designs of a utility's retail rates. They can use this power to ensure that rate designs send the right signals to customers regarding the cost of services that they might request. Major plant additions can be controlled through such means as integrated resource planning, certificates of public convenience and necessity, competitive bidding, and prudence reviews. Wherever regulators and other policymakers can effectively administer mandates there is less need for incentives.

There are nonetheless benefits to complementing mandates with strengthened utility incentives. The case of CDM is illustrative. Poorly incentivized utilities will, for example, not use their considerable influence to proactively promote public policies that encourage CDM, and may oppose such changes.

3. Multiyear Rate Plans

3.1 The Basic Idea

MRPs are the most common approach to incentive regulation around the world. These plans are designed to compensate a utility for its services for several years with revenue that does not closely track the utility's own cost of service. Two components of MRPs are most commonly used to accomplish this.

- A moratorium is imposed on general rate cases that typically lasts four to five years.
- Between rate cases, an **attrition relief mechanism** ("**ARM**") automatically adjusts rates to reflect changing business conditions without linking the relief to the utility's own cost growth.

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

MRPs typically address some costs separately from ARMs using **cost trackers**. A generic formula for revenue escalation is

$$\textit{growth Revenue} = \textit{growth ARM} + Y + Z.$$

Here Y, the "**Y factor"**, indicates the revenue adjustment for costs that are chosen in advance for tracker treatment. The term Z, the "**Z factor"**, indicates the revenue adjustment for miscellaneous hard to foresee changes in cost (and potentially other business conditions. Fuel and purchased power expenses are often Y factored in MRPs. Severe storm costs are often Z factored.

MRPs also typically include **targeted performance incentive mechanisms** (“**PIMs**”). These have in the past been used chiefly to balance incentives for cost containment with incentives to pursue other goals that matter to customers and the public. PIMs used in electric utility MRPs have been especially common for reliability, customer service, and energy efficiency.

Many MRPs feature **earnings sharing mechanisms** that share surplus and/or deficit earnings between utilities and customers. Earnings variations result when the ROE deviates from its public utility commission-approved target. Off-ramp mechanisms may permit review of a plan under pre-specified outcomes such as extreme ROEs.

MRPs can improve utility incentives to embrace distributed energy resources such as CDM and distributed generation if property designed. Inherent advantages include the general incentive MRPs can provide to slow rate base growth. Since CDM is an effective tool for containing capital expenditures (“capex”), utilities have a stronger incentive to embrace them. For example, if a utility uses CDM to reduce the need for substation capex it can keep some of the cost savings for several years. MRPs can also incorporate mechanisms to weaken the short-term link between revenue and sales. For example, an MRP can accommodate revenue decoupling with an ARM that caps revenue growth. A utility’s incentive to embrace CDM under an MRP can be further strengthened by the addition of PIMs that provide rewards for embracing CDM.

The stronger cost containment incentives that MRPs can yield can encourage utilities to reduce CDM expenditures. This problem can be addressed by tracking these expenditures. The combination of an MRP, revenue decoupling, PIMs for CDM, and the tracking of CDM expenses can provide four “legs” for the CDM “stool.”

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

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

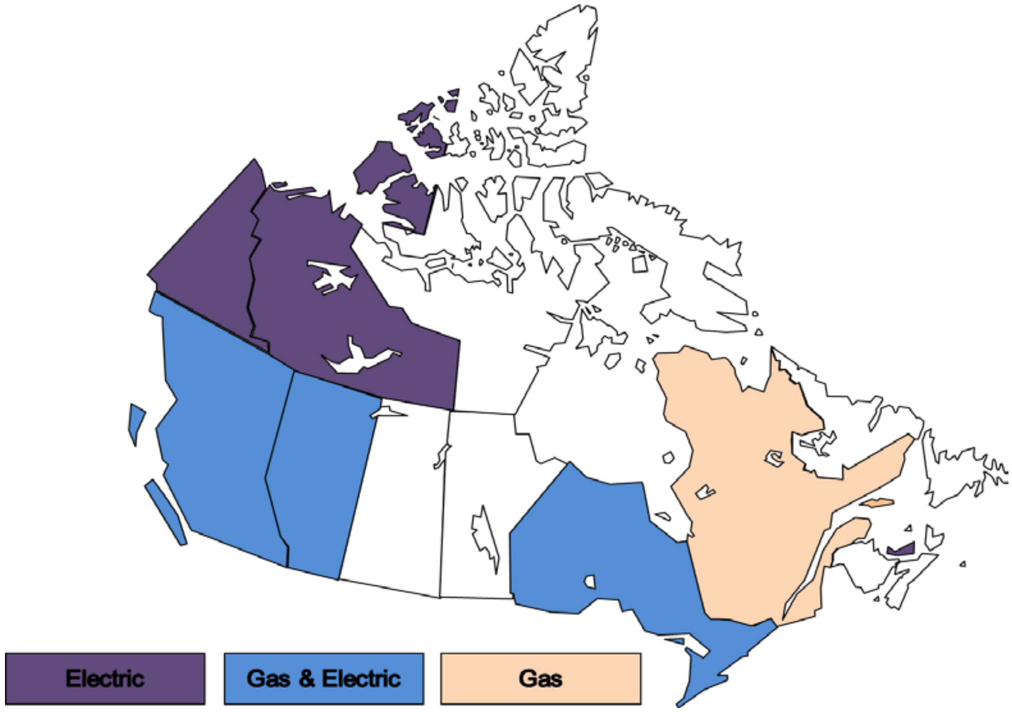
MRPs can also encourage better marketing by utilities where regulators deem this desirable. Rate cases are less frequent, and this reduces the chore of allocating costs across service classes. Rate adjustments that are required (due, for example, to ARMs) can be effected using formulas that insulate one group of customers from rate and service offerings to other customers. The MRP framework therefore reduces concerns about affording utilities more marketing flexibility. MRPs can also permit utilities to keep benefits of improved marketing longer, especially when they feature a well-designed efficiency carryover mechanism. Utilities can then have stronger incentives to develop market-responsive rates and services in targeted areas.

3.2 MRP Precedents

In North America, the use of MRPs began on a large scale in the 1980s. MRPs have been especially popular where utilities have a special need for marketing flexibility. Such plans have helped railroads, oil pipelines, and telecom utilities provide a complex array of rates and services to markets with diverse competitive pressures from common sets of assets where it was impractical to create a separate business for competitive markets. Strong performance incentives were desirable in a period when better performance was needed to meet competitive challenges. In all three industries, the opportunity MRPs provided to keep some benefits of improved performance became a new source of earnings that helped utilities weather increased competition.

Provinces where MRPs are used in Canada are depicted in Figure 1. MRPs are becoming mandatory for natural gas and electric power distributors in the four most populous provinces. Ontario, which regulates more than 70 power distributors, is now on its fourth generation of MRPs for power distributors. Overseas, the privatization of many energy utilities in the last 20 years has forced governments to reconsider their approach to regulation. The majority have

Figure 1 Multiyear Rate Plans in Canada



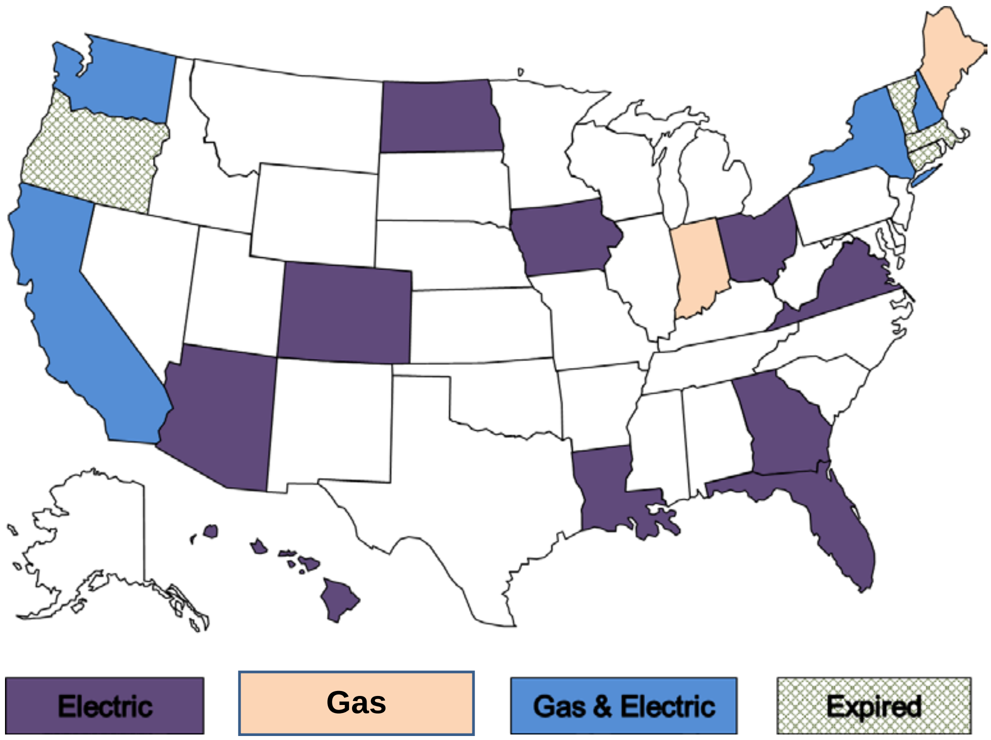
chosen MRPs over the traditional North American approach to regulation for power transmission and distribution alike. Regulators in Australia, Britain, Germany, the Netherlands, New Zealand, and Norway are MRP leaders.

In the U.S. electric utility industry, MRPs have been used on many occasions to regulate retail services of electric utilities. They were first used extensively in California, where a Rate Case Plan was established in the 1980s that, with modifications, still limits the frequency of general rate cases for gas and electric utilities.[10] This has given rise to a great deal of experimentation over the decades. Iowa, Maine, Massachusetts, and New York have also been MRP innovators. States that are currently using MRPs to regulate retail services of gas and electric utilities are indicated in Figure 2. The use of MRPs in the United States has recently

[10] California Public Utilities Commission, 1985

spread to vertically integrated utilities in a diverse collection of other states that includes Colorado, Florida, Georgia, and Washington.[11]

Figure 2 Multiyear Rate Plans in United States



An indication of the potential incentive impact of MRPs can be found in the experience of Central Maine Power ("CMP"), which operated under four successive MRPs from 1995 to 2014. Figure 3 compares the trend in the multifactor productivity of the power distributor services of CMP to those of other distributors in the mid-Atlantic and northeast United States since the mid-1990s.[12]

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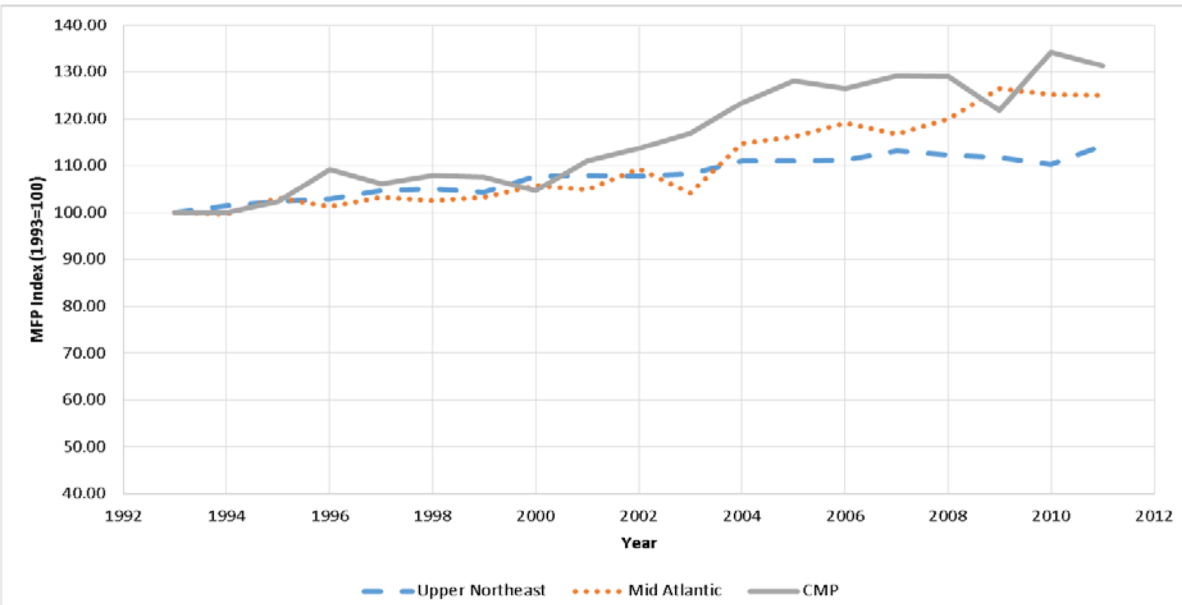
[11] Colorado Public Utilities Commission, 2012; Florida Public Service Commission, 2012; Georgia Public Service Commission, 2010; and North Dakota Public Utilities Commission, 2014.

[12] Mark N. Lowry, Supplemental Productivity Offset Factor Testimony in State of Maine Public Utilities Commission Docket No. 2013-00168, September 2013. Testimony on Behalf of Central Maine Power Company. Accessed at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={F5AAFB65-82CE-43D0-9AA0-BB6F58813B0A}&DocExt=pdf

Figure 3 shows that the company attained productivity growth well above the industry norm during these years. This was accomplished primarily through superior capital productivity growth. The MRPs seem to have encouraged CMP to slow its rate base growth.[13] The superiority of multifactor productivity growth in the Mid-Atlantic states to that in the Northeast is also noteworthy, since several of the best-performing mid-Atlantic utilities operated under lengthy rate freezes during these years with no earnings sharing.

Figure 3 Distribution Productivity Trends of Central Maine Power and Two Peer Groups



3.3 Incentive Power

While CMP's experience under MRPs is promising, the incentive power of MRPs is generally not well understood. In work for various clients over several years PEG Research developed an Incentive Power model to explore the incentive impact of MRPs with certain design features. Key results of this research include the following.

[13] In 2013, CMP made a request for an MRP that would have significantly increased its revenue to allow for new capital expenditures. The CMP rate case was eventually settled, with a stipulation to terminate PBR in Maine and return to a system more akin to COSR. Maine Public Utilities Commission, *Order Approving Stipulation*, Docket No. 2013-00168, August 25, 2014.

- Cost containment incentives are strengthened by longer plan terms and well-designed efficiency carryover mechanisms.
- The incremental incentive impact of lengthening the plan term diminishes.
- Incentives are modestly weakened by earnings sharing mechanisms.

Details of our incentive power research are discussed in the Appendix.

4. ARM Design

The ARM is one of the most important components of an MRP. Such mechanisms can substitute for rate cases as a means to adjust utility rates for trends in input prices, demand, and other external business conditions that affect utility earnings. As such, they make it possible to extend the period between rate cases and strengthen utility performance incentives.

In this section we discuss salient issues in ARM design. Major approaches to ARM design are discussed at a high level. There is a detailed discussion of the indexing approach to ARM design.

4.1 Rate Caps and Revenue Caps

ARMs can escalate rates or allowed revenue. Limitations on rate growth are sometimes called price caps. In a typical price cap plan, allowed price escalation is typically applied separately to multiple service "baskets". There might, for example, be separate baskets for small volume customers, large industrial customers, and customers at risk of bypass. The utility is typically entitled to raise the average prices of the services in each basket by the same percentage permitted by the ARM, Y factor, Z factor, and any earnings sharing adjustments.

The utility might (or might not, depending on design) have some liberty to raise prices to some customers *within* a basket by less than price cap index growth and make up for it by raising prices for other customers in the basket more rapidly. However, customers in each basket are insulated from the discounts and other market developments going on with services in other baskets, except as these developments influence earnings sharing.

Price caps have been widely used to regulate industries, such as telecommunications, where it is vitally important to promote marketing flexibility while insulating core customers from its consequences. When usage charges exceed the marginal cost of service, price caps make utility earnings more sensitive to system use and thereby incent utilities to encourage greater use.

Under revenue caps, the focus of escalator design is growth in allowed revenue (aka the revenue requirement or "budget"). The allowed revenue yielded by a revenue cap escalator in a given year must be converted into rates, and this conversion requires assumptions regarding billing determinants. Rate growth may not equal revenue growth due to growth in billing determinants.

Under revenue caps, the same issue arises as to how to allocate the ARM, Y factor, Z factor, and any earnings sharing adjustments between service baskets. Typically, the utility will have the right to raise its revenue by the same percentage for each basket. There is no opportunity to escalate the revenue growth permitted for one service basket by less than the full allowance and then make up for it with more rapid escalation of the revenue in another basket.

Revenue caps are often paired with a revenue decoupling mechanism that removes disincentives to promote efficient energy use. However, revenue caps have intuitive appeal with or without decoupling since revenue cap escalators deal with the drivers of *cost* growth, whereas price cap escalators must consider additionally the trends in billing determinants. As a consequence, revenue caps are sometimes used even in the absence of decoupling. Current examples of companies that operate under revenue caps without decoupling include two gas distributors in Alberta.

4.2 Basic Approaches to ARM Design

There are several well-established approaches to ARM design. Most can be used to escalate rate or revenue caps. We discuss each in turn.

4.2.1 Forecasts

The Basic Idea

A forecast-based ARM is based entirely on multi-year forecasts. In the United States, a revenue cap ARM based on forecasts typically increases revenue by a certain predetermined percentage in each year of the plan (e.g., 4% in 2014, 5% in 2015, 3% in 2016, etc.). This gives allowed revenue a "stairstep" trajectory.

When forecasting cost growth, the cost of capital can be calculated using familiar utility accounting. A forecast of the trend in the older capital stock depends chiefly on mechanistic depreciation and is relatively straightforward. The more controversial issue and a major focus of a proceeding to approve a forecasted ARM is the level of plant additions during the plan term.

There is typically no adjustment to rates during the plan term if plant additions are higher or lower than the forecasts. In the next rate case, however, rates are trued up to the approved test year rate base. Since rate escalation is unaffected by the utility's cost during the plan, this approach to ARM design can generate strong capex containment incentives despite the use of forecasts.

Forecasts are sometimes subject to an inflation-based true-up. In Britain, for example, revenue requirements based on forecasts are adjusted for actual inflation in a macroeconomic price index. Capital cost can in principle be adjusted for actual inflation in a construction cost index or the trend in the market rate of return.

Shortcuts are sometimes taken in the preparation of forecasts. For example, capex may be set for each year at its average for recent years or at its value for the test year of a rate case, as adjusted for construction cost inflation. The forecast of O&M expenses may be escalated using a formula that takes account of inflation, the industry productivity trend, and growth in the utility's demand.

Precedents

The Office of Gas and Electricity Markets ("Ofgem") in Britain uses inflation-adjusted ARMs based on cost forecasts. The British approach to ARM design is sometimes called the "building block" approach since the revenue requirement is built up from detailed cost forecasts. In Canada, the Ontario Energy Board ("OEB") permits the use of forecast-based ARMs in "custom" incentive regulation plans and such plans have recently been proposed by several power distributors.

Forecasts have been the most common basis for ARM design in the United States. They are currently used by electric utilities in California, Georgia, North Dakota, and New York. Some gas distributors in New York state operate under revenue *per customer* caps with stairstep trajectories.

Pros and Cons

A salient advantage of forecast-based ARMs is their ability to accommodate a variety of capex plans. Commissions accustomed to processing rate cases with forward test years have some of the skills needed to consider multiyear cost forecasts. Some commissions are also engaged in multi-year planning exercises such as the integrated distribution planning underway in California. These exercises reduce the incremental cost of developing ARMs based on cost forecasts.

ARMs based on forecasts which have stairstep trajectories do not adjust to unforeseen inflation risk. The biggest challenge with forecast-based ARMs, however, is the difficulty of choosing a multiyear total cost forecast. The British have extensive experience with forecast-based ARMs. Approved budgets for capex have often exceeded actual capex. This may reflect a deliberate policy of forecast overstatement by utilities but may also reflect their discovery, under the force of the performance incentives provided by MRPs, that lower cost is achievable.

Ofgem and its predecessors have expressed concerns about exaggerated capex forecasts for many years. For example, underspends occurred in a period when high capex was anticipated 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 Office of Electric Utility Regulation ("Offer") accepted the need for a high level of replacement capex. Offer stated that

> a significant increase in capital expenditure could be justified for many companies by the need to replace equipment which was nearing the end of its useful life. Although no single life expectancy figure is valid, in very general terms heavy electrical equipment can be expected to last around 40 to 50 years. As a result of this large scale investment in electricity distribution which took place in the 1950s and 1960s an increasing proportion of companies' equipment will reach this point in the review period. To avoid a reduction in the quality of supply received by customers, plant replacement will need to increase, alongside the continuing development of methods to extend plant life.[14]

Offer did reduce 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 Offer examined the companies' actual and proposed capex and for the expiring price control prepared a figure, presented below, that showed that actual capex was lower than Offer's approved levels in the prior price control review. Offer came to the conclusion that the "echo effect" was less pronounced than it had feared. Offer

[14] Offer, *The Distribution Price Control: Proposals*, August 1994, p. 59 at 5.41.

subsequently hinted that utilities had been deferring capex in year one of the price controls to maximize their profitability. It commented that

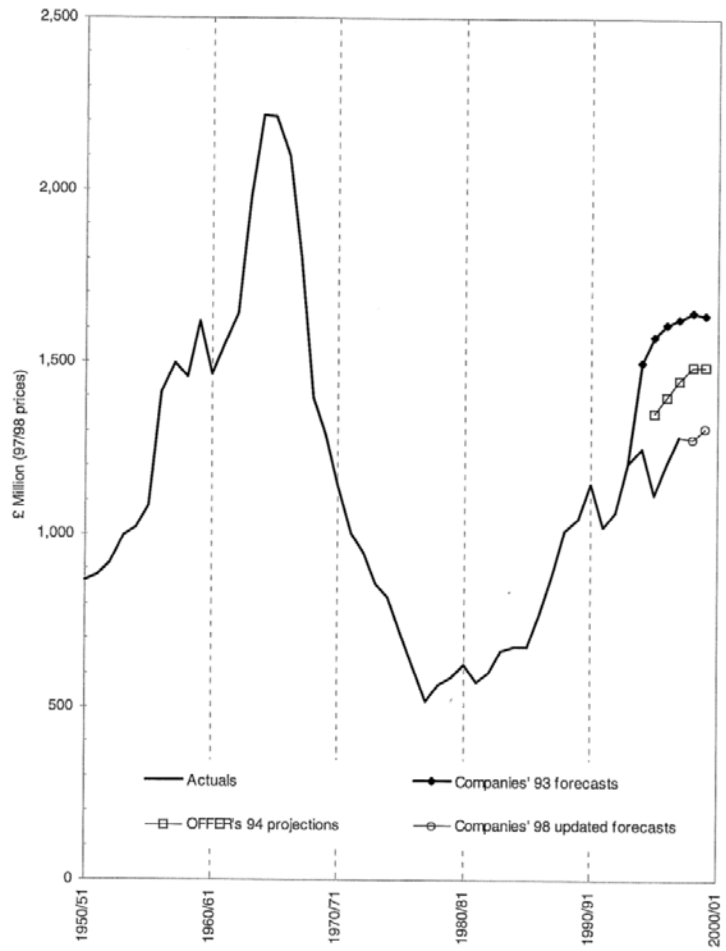
> The significant peak in investment during the 1950s and 60s might be thought to have implications for the future timing of asset replacement. In practice, the asset replacement investment profile should be determined by the useful lives of these assets, typically ranging between 40 and 70 years, and the extent to which certain of these assets may have become redundant or displaced by later network developments. As a consequence significant smoothing of asset replacement is anticipated and the historical expenditure peak is not expected to be repeated.[15]

This experience required the regulator, now called the Office of Gas and Electricity Markets ("Ofgem"), to consider the implications of extensive capex underspends in developing a new price control.[16] It began by assessing its policy on underspending, asserting that

> 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 scrutinised. [17]

[15] Offer, Review of Public Electricity Suppliers 1998-2000, Distribution Price Control Review: Consultation Paper, May 1999, p. 46.
[16] During the course of the proceeding, Offer merged with the British gas regulator Ofgas to become Ofgem.
[17] Ofgem (1999), Reviews of Public Electricity Suppliers (1998-2000), Distribution Price Control Review: Draft Proposals, p. 41.

FIGURE 4.2: DISTRIBUTION BUSINESS CAPITAL EXPENDITURE (1997/98 PRICES)



Further,

> 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. [18]

Ofgem penalized three companies in its final decision that had provided exaggerated forecasts of capex and operating expenditures. Nevertheless, it became apparent that the

[18] Ofgem (1999), Reviews of Public Electricity Suppliers, Distribution Price Control Review: Draft Proposals, p. 7.

forecasting overstatements had continued in the third price control period. In a policy document for the fourth price control review, designed to start in 2004, Ofgem found that capex was being underspent by the utilities under the first three years of the new price control by nearly £300 million. Many power distributors were also providing forecasts describing a need for capex increases that were more than 20 percent greater than the previous forecasts.

Due in part to experiences like these, Ofgem has over the years commissioned numerous statistical benchmarking and engineering studies to develop its own independent view of required cost growth. In 2004, it added an incentive mechanism to the MRP designed to encourage more accurate capex forecasts. It enabled distributors with

> less well justified capex forecasts, as compared with the views of Ofgem's consultants … 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.[19]

An Information Quality Incentive ("IQI") of similar design was extended to cover most O&M and capital expenditures in the fifth electricity distribution price control in 2009 and continues to operate today. An IQI was also applied to gas distributors in 2007 and was renewed for use in the current gas distribution price control.

Other regulators that use forecast-based ARMs have taken similar steps to develop stronger independent views of cost forecasts. The Australia regulator, for example, makes extensive use of statistical benchmarking in power distribution ratemaking. The Ontario Energy Board requires power distributors to file benchmarking and productivity evidence in support of customer IR plans and undertakes its own benchmarking studies. Benchmarking has played a smaller role in transmission benchmarking around the world due in part to the much smaller number of transmission utilities in each country.

[19] Ofgem (2009), Regulating Energy Networks for the Future: RPI-X @ 20: History of Energy Network Regulation, p. 38.

4.2.2 Indexing

The Basic Idea

An indexed ARM is developed using industry cost trend research. As discussed further in Section 4.3, the following general formula drawn from cost theory is useful in the design of revenue caps.

growth Cost = growth Input Prices – growth Productivity + growth Scale.

When the scale of the utility business is multidimensional, its growth can be measured by a scale index, the growth of which is a weighted average of several scale variables. In energy distribution, the number of customers served has been found to be a useful standalone measure of operating scale. This provides the foundation for the following revenue cap index.

growth Revenue = Inflation – X + growth Customers

where a recent measure of price inflation is used. X, the "productivity" or "X" factor, reflects the average historical productivity trend of a group of distributors. ARM escalation therefore reflects normal productivity growth, to the benefit of customers. A "stretch factor" (aka consumer dividend) is often added to X to share with customers the benefit of the stronger performance incentives expected under the plan.

Broad regional or national peer groups are commonly used to establish the base productivity trend. It is generally necessary for the regulator to develop an independent view of the appropriate index formula by commissioning an independent productivity study. These studies can be managed by the Commission or intervenors. The former approach has been used in Alberta and Ontario whereas the latter approach has been used in British Columbia. While controversy is common concerning peer groups or productivity measurement methods, the base productivity trends chosen by North American regulators have tended to be around 1 percent.

Precedents

The indexing approach to the design of attrition relief mechanisms originated in the United States.[20] Development was facilitated there by the availability of standardized high quality data for numerous companies in several utility industries. First applied in the railroad

[20] Early American papers discussing the use of input price and productivity research in ARM design include Sudit (1979) and Baumol (1982).

industry, index-based ARMs have subsequently been used to regulate telecom, gas, electric, and oil pipeline utilities. California, Maine, and Massachusetts were early adopters in retail energy utility regulation. U.S. energy utilities that have operated under index-based ARMs include Bay State Gas, Boston Gas, Central Maine Power, San Diego Gas & Electric, Southern California Gas, and NSTAR Electric. Indexed based price caps are currently used by the Federal Energy Regulation Commission to regulate U.S. oil pipelines.

ARMs based chiefly on indexing research are now used more widely to regulate utilities in Canada than in the United States. For example, power distributors in Alberta, British Columbia, and Ontario currently operate under MRPs with ARMs designed with the aid of indexing research. Index-based ARMs are also used in Canadian rail regulation and have been used in Canadian telecom regulation. Distributors in New Zealand are also regulated using index-based ARMs.

Pros and Cons

Index-based ARMs compensate utilities automatically for key external cost drivers such as inflation and demand growth. This reduces operating risk without weakening performance incentives. Customers can be guaranteed the benefit of productivity growth that is superior to the industry norm.

Index-based ARMs do not fully compensate utilities for cost surges. Necessary cost surges can be addressed by cost trackers, but trackers involve their own complications as we discuss further below. The design of index-based ARMs can involve statistical cost research that is complex and sometimes controversial.

4.2.3 Hybrid ARMs

The Basic Idea

"Hybrid" approaches to ARM design use a mix of index research and cost forecasts.[21] The most popular hybrid approach in the United States is to index utility revenue that compensates utilities for O&M expenses while using forecasts for capital cost revenue.

[21] A "hybrid" designation can in principle be applied to a number of ARM design methods, including that used in Britain.

Pros and Cons

Indexing for O&M expenses provides protection from hyperinflationary episodes and limits the scope of forecasting evidence. Good data on O&M input price trends of utilities are available in the United States. The idea of indexing a utility's O&M compensation has such appeal that it is sometimes used outside the context of a comprehensive multiyear rate plan. For example, indexing has been used to escalate test year O&M expenses in Massachusetts. The forecast approach to capital costs, meanwhile, accommodates diverse capital cost trajectories. The complicated issue of designing index based ARMs for total cost is sidestepped.

On the other hand, we have shown that capital cost forecasts can be complex and controversial. Custom indexes of utility O&M input price inflation are readily available in Canada.

Precedents

The hybrid approach to ARM design was pioneered in California. The restriction on rate case frequency there has encouraged a great deal of ARM design experimentation. The hybrid approach has been found to be adaptable to the diverse cost trajectories of California's gas and electric utilities and has been used from time to time before and after the restructuring of the electric power industry. The hybrid approach has recently been used in the ARMs of Southern California Edison and the three Hawaiian Electric utilities.

Another interesting hybrid approach to ARM design has developed recently in the United States that is especially popular for vertically integrated electric utilities. Rates or revenue are escalated for the expected cost of major plant additions. It is assumed that the residual cost not addressed by trackers grows slowly enough that there is no need for other rate escalation. This approach has recently been used in Arizona, Colorado, Florida, and Georgia.

4.2.4 Rate Freezes

Some MRPs feature a rate freeze in which the ARM provides no rate escalation during the plan.[22] Revenue growth then depends on growth in billing determinants and tracked costs.

[22] An analogous concept for an MRP with revenue decoupling might be a revenue per customer freeze like those typically associated with revenue decoupling for gas distributors. Revenue then grows at the typically gradual rate of customer growth.

Freezes usually apply only to base rates but sometimes apply to rates for commodity procurement.[23]

Rate freezes have recently been approved for several U.S. electric utilities. These are typically vertically integrated utilities with limited need to increase generation rate base. Provided that a few costs that are growing are tracked, they do not need any further rate escalation for several years. Quite often, the tracked cost includes the cost of the generating plant additions. This approach has been used by VIEUs in Arizona, Florida, Louisiana, and Virginia.

4.2.5 Incentive-Compatible Menus

ARM design can be aided by "incentive-compatible" menus of MRP provisions designed to incentivize utilities to reveal their achievable cost through their choices between menu options. The menus typically include a key ARM provision and another key plan provision affecting utility finances. 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 and Paul Kleindorfer, and Nobel prize winning economist Jean Tirole.

Menus can be applied to forecast, indexing, and hybrid approaches to ARM design. In the context of an index based ARM, for example, the utility might be presented with various combinations of X factors and earnings-sharing mechanisms. A lower X factor might be combined with a lower share of surplus earnings. In the context of a forecast based ARM, in contrast, a utility might be presented with a menu featuring various combinations of cost forecasts and earnings sharing provisions. ~~A lower X factor might be combined with a lower share of surplus earnings.~~

Precedents

Since 2004, we have noted that Ofgem has employed mechanisms like the Information Quality Incentive that feature menus to help determine the revenue requirements of utilities. The menus consist of cost forecast-allowed revenue combinations. Each utility is asked to give a cost forecast and is given an allowed revenue amount based on the specified forecast. The IQI's

[23] MidAmerican Energy operated under a comprehensive rate freeze for many years. The company benefited from high sales for resale margins.

input on allowed revenue is in two parts; an 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 the IQI adjustment factor formula.

The ex-ante allowed revenue is a weighted average of the regulator's cost forecast and the utility's cost forecast. The regulator's forecast receives 75% weight while the utility's forecast receives 25% weight. The IQI adjustment factor is composed of an incentive rate and an ~~ex-post~~ additional income factor. The incentive rate specifies the sharing, between the utility and consumers ,of expenditure variances ~~between the utility and consumers,~~ between the utility's actual expenditures and its ex-ante allowed revenue. The incentive rate increases as the variance between the utility's cost forecast and regulator's cost forecast decreases. The ~~ex-post~~ additional income factor ~~is~~ rewards the utility for a cost forecast that is at or below Ofgem's own forecast. Together these provisions make ~~calculated to make~~ the menu incentive compatible: the utility maximizes profits when its actual cost matches its cost forecast and it pursues maximum possible cost savings throughout the plan term. ~~The incentive rate is designed to create incentives to cut costs, while the additional income factor is calculated to incentivize the utility to provide accurate forecasts.~~ There are minimal gains from proposing a high forecast and subsequently incurring low costs.

The menu developed for the 2010-2015 plan and presented in Ofgem (2009) is given in the matrix below. The first line of the matrix is a ratio between the utility's cost forecast and the regulator's cost forecast. A ratio of less than 100 means the utility is forecasting a lower cost 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 incentive rate increases as the ratio of the utility's forecast to the regulator's forecast decreases in order to provide greater incentives for the utility to cut costs and improve productivity to 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. The values which begin in the second ~~column~~ section labeled IQI Adjustment factor ~~are~~ illustrate the possibilities for additional revenue the utility is allowed to collect once it reports its actual expenditures for the ~~previous year~~price control period, expressed as percentages of the regulator's cost estimate. Incentive compatibility is represented by the shaded boxes. For each value of the ratio between actual expenditure and Ofgem's forecast expenditure, the utility receives the highest adjustment when that ratio equals the utility expenditure forecast to regulator expenditure forecast ratio. Cost cutting incentives are represented by the fact that in all cases the utility receives additional revenue by cutting costs. The IQI adjustment factor is highest when the utility's actual expenditures match or are less than its own forecast of expenditures.

IQI Matrix for Ofgem's 5th Distribution Price Control Review

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 a~~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

In the United States, the Federal Communications Commission used a menu approach to MRP design in a 1990 price cap plan for interexchange access services of some local telecommunications exchange carriers. Under the plan, the target rate of return was set at 11.25%. The company could choose between two X-factor-sharing factor options. The first option set the X-factor at 3.3% and entitled the company to retain all of its earnings until it achieved a 12.25% rate of return. Earnings between 12.25% and 16.25% would be shared equally with consumers and earnings above 16.25% would go fully to consumers. The second option allows a company to elect an X-factor of 4.3% and in return retain all of its earnings until it reached a 13.25% rate of return. Equal sharing of earnings would occur between 13.25% and 17.25%, and consumers would receive all earning above 17.25%

4.2.6 Role of Benchmarking

Statistical benchmarking is useful in all of the approaches to ARM design we have discussed. The relevance of benchmarking is elucidated by the following formulaic decomposition of the efficient cost of service for next year.

$$Cost_{t+1}^{Efficient} = Cost_t^{Actual} \ x \ (Cost_t^{Efficient} / Cost_t^{Actual}) \ x \ (Cost_{t+1}^{Efficient}/Cost_t^{Efficient}).$$

It can be seen that the efficient cost of service in a future year depends on both a utility's current degree of inefficiency, and on the growth in efficient cost over time. Growth in a utility's efficient cost depends on diverse conditions that include growth of input prices, operating scale, and productivity. This analysis helps to explain why statistical benchmarking of a utility's recent cost level and statistical research on industry input price and productivity trends are *both* useful in ensuring that an ARM provides benefits to customers.

We have noted benchmarking and productivity research are used extensively by regulators that use forecasted ARMs. In Australia the nation's largest power distributor, Ausgrid, a public enterprise, was recently subject to a large revenue disallowance based on the results of a statistical benchmarking study.

The Ontario Energy Board regulates most power distributors with MRPs featuring price cap indexes of "inflation – X" form. The X factor is based in part on the trend in the productivity of Ontario utility distribution companies and in part on a stretch factor that is tied mechanistically to a Board-commissioned econometric benchmarking study. The Board also permits "custom" MRPs that feature forecast-based ARMs but requires that these ARMs be designed using benchmarking and productivity research.

In recent years, we have noted that Ofgem has used an Information Quality Incentive involving incentive-compatible menus to encourage utilities to provide more reasonable cost forecasts. It is relatively easy to design an incentive compatible menu that encourages a utility to reveal its expectation about future costs. The hard part is to make sure that the menu affords customers a fair share of the benefit of efficient operation. Statistical cost and engineering research is useful in designing menus that ensure customer benefits. Engineering and statistical cost research are thus a complement rather than a substitute for a menu-based approach to ARM design which benefits customers.

4.3 Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design ~~the O&M component of a hybrid ARM~~attrition relief mechanisms. To understand the logic it is helpful to first have a high level understanding of input price and productivity indexes.

4.3.1 Input Price and Quantity Indexes

The growth trend in a company's cost can be shown to be the sum of the growth in an appropriately designed input price index ("*Input Prices*") and input quantity index ("*Inputs*").

$$\textit{trend Cost} = \textit{trend Input Prices} + \textit{trend Inputs} \qquad [1]$$

These indexes summarize trends in the input prices and quantities that make up the cost. A cost-weighted input *price* index measures the impact of price inflation on the cost of a bundle of inputs. A cost-weighted input *quantity* index measures the impact of quantity growth on cost. Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by electric utilities like Hydro-Québec.

Calculation of input quantity indexes is complicated by the fact that firms typically use numerous inputs in service provision. This complication is contained when summary input price indexes are readily available for a group of inputs such as labor. Rearranging the terms of [1] we obtain

$$\textit{growth Inputs} = \textit{growth Cost} - \textit{growth Input Prices.} \qquad [2]$$

This residual approach to input quantity trend calculation is widely used in productivity research. We can, for example, calculate the growth in the quantity of labor by taking the difference between salary and wage expenses and a salary and wage price index.

Both indexes use the cost share of each input group that is itemized in index design as weights. In power distribution, the weight on capital inputs is quite high. In power transmission the weight is even higher.

4.3.2 Productivity Indexes

Basic Idea

A productivity index is the ratio of an output quantity index ("*Outputs*") to an input quantity index.

$$Productivity = \frac{Outputs}{Inputs}. \qquad [3]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they offer. Some productivity indexes are designed to measure productivity *trends*. The growth trend of such a productivity index is the *difference* between the trends in the output and input quantity indexes.

trend Productivity = trend Outputs – trend Inputs. [4]

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 and/or the uneven timing of certain expenditures. Volatility tends to be greater for individual companies than for an aggregation of companies such as a regional industry.

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 ("*MFP*") index measures productivity in the use of multiple inputs.

Output Indexes

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. In designing an output index, choices concerning subindexes and weights should depend on the manner in which the index is to be used.

One possible objective is to measure the impact of output growth on *revenue*. In that event, the subindexes should measure trends in *billing determinants* and the weight for each itemized determinant should be its share of revenue.[24] In this report we denote by $Outputs^R$ an output index that is revenue-based in the sense that it is designed to measure the impact of output on revenue. A productivity index that is calculated using $Outputs^R$ will be labeled $Productivity^R$.

$$\text{trend } Productivity^R = \text{trend } Outputs^R - \text{trend } Inputs. \qquad [5a]$$

Another possible objective of output research is to measure the impact of output growth on company *cost.* In that event it can be shown that the subindexes 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. 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. A productivity index calculated using a cost-based output index will be labeled $Productivity^C$.

$$\text{trend } Productivity^C = \text{trend } Outputs^C - \text{trend } Inputs. \qquad [5b]$$

This 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 another important source of productivity growth. These economies are available in the longer run if cost has a tendency to grow less rapidly than output. A company's potential to achieve incremental scale economies depends on the pace of its workload growth. Incremental scale economies (and thus productivity growth) will typically be reduced the slower is output growth.

A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth will increase (decrease) to the extent that X inefficiency

[24] This approach to output quantity indexation is due to the French economist Francois Divisia.

diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current efficiency level.

Another driver of productivity growth is changes in the miscellaneous 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 percentage of lines that are undergrounded will tend to lower O&M expenses and accelerate O&M productivity growth.

4.4 Use of Index Research in Regulation

4.4.1 Price Cap Indexes

Early work to use indexing in ARM design focused chiefly on *price* cap indexes ("PCIs"). We begin our explanation of the supportive index logic by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[25] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost.} \qquad [6]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices*") and billing determinants ("*Outputs*")

$$\textit{trend Revenue} = \textit{trend Outputs}^{R} + \textit{trend Output Prices}. \qquad [7]$$

Recollecting from [2] that the trend in cost is the sum of the growth in cost-weighted input price and quantity indexes, it follows that the trend in output prices that permits revenue to track cost is the difference between the trends in an input price index and a multifactor productivity index of MFP^R form.

$$\begin{aligned} \textit{trend Output Prices}^{R} &= \textit{trend Input Prices} - (\textit{trend Outputs}^{R} - \textit{trend Inputs}) \qquad [8] \\ &= \textit{trend Input Prices} - \textit{trend MFP}^{R}. \end{aligned}$$

The result in [8] provides a conceptual framework for the design of PCIs of general form

$$\textit{trend Rates} = \textit{trend Inflation} - X\ . \qquad [9a]$$

---

[25] The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

Here X, the "X factor", is calibrated to reflect a base MFP^R growth target ("$\overline{MFP^R}$"). A "stretch factor", established in advance of plan operation, is often added to the formula which slows PCI growth in a manner that shares with customers the financial benefits of performance improvements that are expected during the MRP.[26]

$$X = \overline{MFP^R} + Stretch \qquad [9b]$$

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.

4.4.2 Revenue Cap Indexes

General Result

Mathematical theory can be used to design revenue cap indexes based on rigorous input price and productivity research. Several approaches to the design of revenue cap indexes are consistent with index logic. One approach is grounded in the following basic result of cost research:

$$growth\ Cost = growth\ Input\ Prices - growth\ Productivity^C + growth\ Outputs^C. \qquad [10a]$$

Cost growth is the difference between input price and cost efficiency growth plus the growth in operating scale as measured by a cost-based output index. This result provides the basis for a revenue cap escalator of general form

$$growth\ Revenue = growth\ Input\ Prices - X + growth\ Outputs^C \qquad [10b]$$

where

$$X = \overline{MFP^C} + Stretch\,. \qquad [10c]$$

Application to Power Distribution

In gas and electric power distribution, we have noted that the number of customers served is a useful scale variable for a revenue cap index. It is an important cost driver in its own right and also highly correlated with other cost drivers such as peak load. The latter attribute is especially useful when the revenue cap index is used to support revenue decoupling. For a power distributor, $Outputs^C$ can be reasonably approximated by growth in the number of

[26] Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

customers served and there is no need for the complication of a multidimensional output index with cost elasticity weights. Relation [10a] can then be restated as

growth Cost

= growth Input Prices – (growth Customers – growth Inputs) + growth Customers

= growth Input Prices – growth MFP^N *+ growth Customers* [11a]

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

Rearranging the terms of [11a] we obtain

growth Cost – growth Customers

= growth (Cost/Customer) = growth Input Prices – growth MFP^N. [11b]

This provides the basis for the following revenue per customer ("RPC") index formula.

growth Revenue/Customer = growth Input Prices – X + Y + Z [11c]

where

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

This general formula for the design of revenue cap indexes that are currently used in the MRPs of Gazifère, ATCO Gas, and AltaGas in Canada. The Régie de l'Energie in Québec recently directed Gaz Métro to develop an MRP featuring revenue per customer indexes. Revenue per customer indexes were previously used by Southern California Gas and Enbridge Gas Distribution ("EGD"), the largest gas distributors in the US and Canada, respectively.

<u>Application to Power Transmission</u>

The appropriate scale escalator for a power transmission utility is less clear. The drivers of transmission cost include peak load, the distance over which power must be carried, and the degree to which loads must be received from local generators and delivered to local loads. This long list suggests the need for a *multidimensional* scale index. Appropriate weights can be obtained from econometric research on the drivers of power transmission cost.

Inclusion of peak load in the scale index of a revenue cap index for a transmission utility would strengthen the utility's incentive to expand peak load. It may be desirable then, to replace peak load in the scale index with one or more variables representing peak load *drivers* like the generation capacity and number of retail customers in the service territory.

<u>Application to O&M Expenses</u>

Our reasoning provides for a general formula for escalating utility revenue that compensates a utility for O&M expenses. This formula provides the basis for an O&M escalator in a hybrid ARM and for productivity-based budgeting in an all-forecast ARM. The general formula is

$$\textit{growth Cost}_{O\&M} = \textit{growth Input Prices}_{O\&M} - \textit{growth Productivity}_{O\&M}{}^{C} + \textit{growth Outputs}_{O\&M}{}^{C}. \qquad [12a]$$

This provides the basis for the following O&M escalator:

$$\textit{growth Revenue}_{O\&M} = \textit{growth Input Prices}_{O\&M} - X + \textit{growth Outputs}_{O\&M}{}^{C} + Y + Z \qquad [12b]$$

$$X = \textit{growth Productivity}_{O\&M}{}^{C} + \textit{Stretch}. \qquad [12c]$$

O&M cost escalation formulas like [12b] are an example of "productivity-based budgeting" and have been used by regulators in Australia to establish multiyear O&M budgets for energy distributors.

Implementation of the formula requires estimation of the O&M productivity trend (which may differ considerably from the multifactor productivity trend) and the development of an appropriate scale index. Drivers of distribution O&M expenses might include line miles, the number of customers served, and substation capacity. Drivers of transmission O&M expenses include line miles and substation capacity. Appropriate weights can be obtained from econometric research on the drivers of O&M cost using data from the relevant industry.

4.5 Index Research for ARM Design

4.5.1 Capital Cost

Trends in the price and quantity of capital play a critical role in the measurement of trends in multifactor productivity and the prices of base rate inputs due to the typically high share of capital in total cost. A practical means must be found to calculate capital cost and to decompose it into consistent price and quantity indexes such that

$$\textit{growth Cost}^{Capital} = \textit{growth Price}^{Capital} + \textit{growth Quantity}^{Capital}. \qquad [13]$$

The capital price index measures the trend in the cost of owning a unit of capital. It is sometimes called a rental or service price because in a competitive market the price of rentals would tend to reflect the unit cost of capital ownership. The components of capital cost include depreciation and the return on investment. The trend in these costs depends on trends in construction prices and the market rate of return on capital. A capital price index should reflect both of these price trends.

Three practical methods that have been developed for calculating capital costs in indexing studies merit note.

- The geometric decay ("GD") method assumes a current valuation of capital and a constant rate of depreciation. This method has been widely used in productivity research. Although the assumptions underlying the GD method are very different from those used to compute capital cost in utility regulation, the GD method has been used on several occasions in research intended to calibrate utility X factors. The assumptions produce capital service price and quantity indexes that are mathematically simple and easy to code and review.
- The one hoss shay approach to capital costing assumes that plant does not depreciate gradually but, rather, all at once as the asset reaches the end of its service life. The plant is valued in current dollars. Although the assumptions underlying the one hoss shay method are very different from those used to compute capital cost in utility regulation, the method has been used occasionally in research intended to calibrate utility X factors.
- The cost of service ("COS") approach to calculating capital cost, prices, and quantities is designed to approximate the way capital cost is calculated in utility regulation. This approach is based on the assumption of straight line depreciation and the historic (book) valuation of capital. PEG Research personnel have used this approach in a number of X factor studies.

Utilities have diverse methods for calculating depreciation and the depreciation treatments of individual utilities change over time. In calculating capital costs and quantities, it is therefore generally considered desirable to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment. Since the quantity of capital on hand may involve plant added thirty to fifty years ago, it is desirable to have gross plant addition data for many years in the past. For older periods in which plant addition data are unavailable, it is customary to consider the net plant value near the end of this period and then estimate the quantity of capital it reflects using construction price indexes from earlier years and assumptions about the pattern of investment. The year in which this exercise takes place is commonly called the "benchmark year". Since this exercise is unlikely to be exact, it is advisable to base X factor research on a sample period that begins at least ten years after the benchmark year.

4.5.2 Choosing a Productivity Peer Group

Research on the productivity of other utilities can be used in several ways to calculate base productivity targets. Using the productivity trend of the entire industry to calibrate X is tantamount to simulating the outcome of competitive markets. A competitive market paradigm has broad appeal.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion in Section 4.3.2 of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause different utilities to have different productivity trends. For example, power distributors experiencing slow growth in the number of electric customers served are less likely to realize economies of scale than distributors that are experiencing rapid growth. There is thus considerable interest in methods for customizing base productivity targets to reflect local business conditions. The most common approach to date has been to calibrate the X factor for a utility using the productivity trends of *similarly situated* utilities.

A variety of peer groups are sometimes available. In choosing among these, we are guided by the following principles. First, the group should either exclude the subject utility or be large enough that the average productivity trend is substantially insensitive to the actions of the subject utility. This may be called the externality criterion. It is desirable, secondly, for the group to be large enough that the productivity trend is not dominated by the actions of a handful of utilities. This may be called the size criterion. A third criterion is that the group should be one in which external business conditions that influence productivity growth are similar to those of the subject utility. This may be called the "no windfalls" criterion.

Data on the operations of US utilities are well-suited for the requisite price and productivity research. Standardized data of good quality have been available from the federal government for a large number of utilities for many years. The primary source of this data is the FERC Form 1, which provides detailed cost data and some data on operating scale. The cost data must conform to a uniform system of accounts. These data have been available for decades, providing the basis for more accurate capital quantity indexes. The accuracy of these indexes is very important in studies of T&D productivity. Useful data are available from private vendors on electric utility operation and maintenance and construction cost trends.

PEG Research personnel have frequently used regional rather than national data samples in ARM design where this doesn't violate the size and externality criteria. In the Northeast United States, for example, X factors in index-based PBR plans have usually been calibrated using research on the productivity trends of Northeast utilities. Within a broad region, we search for a group of companies that experiences conditions for MFP growth that are similar to those of the subject utility on balance. The relevant conditions for an energy distributor include the pace of electric customer growth, growth in the number of gas customers served, and changes in the extent of undergrounding.

Unfortunately, the number of utilities, for which good data are available, which face productivity growth drivers similar to those facing the subject utility is sometimes limited. This is a chronic problem in Canada, where standardized data that could be used to accurately measure the productivity trends of numerous utilities are not readily available and there are few potential peers for HQD and HQT in any event. Since most of Canada's economy lies close to the US border, utilities in adjacent American states could be used as a peer group. However, the economy across the border is often different from Canada's in important respects.

Standardized operating data have recently become available for the numerous Ontario power distributors, but these have a number of limitations.

- Most companies in the Ontario sample are small municipal distributors.
- Many companies have recently changed accounting standards.
- Breakdowns of O&M expenses into labor and other inputs are unavailable.
- Plant value data needed to construct accurate capital quantity indexes are not available for a lengthy sequence of years.
- The gross plant value data that are preferred for use in capital quantity index construction are unavailable.

Due to the limitations of Canadian data, regulators in Alberta and British Columbia have based X factors in their MRPs for gas and electric power distributors on the productivity trends of national samples of US distributors. The Ontario Energy Board used estimates of national US productivity trends to choose the productivity target in its third generation plan for power distributors.

Complications like these have occasionally prompted regulators to base X factors on a utility's *own* recent historical productivity trend. This approach will weaken a utility's incentives to increase productivity growth if used repeatedly. Furthermore, a utility's productivity growth in one five or ten year period may be very different from its productivity growth potential in the following five years.

4.5.3 Data Quality

The quality of data used in index research has an important bearing on the relevance of results for the design of MRPs. Generally speaking, it is desirable to have publicly available data drawn from a standardized collection form such as those developed by government agencies. Data quality also has a temporal dimension. It is customary for statistical cost research used in MRP design to include the latest data available.

4.5.4 Inflation Measure Issues

Index logic suggests that the inflation measure of an ARM should in some fashion track the input price inflation of utilities. For incentive reasons, it is preferable that the inflation measure track the input price inflation of utilities *generally* rather than the prices actually paid by the subject utility. Inflation measures of this kind are also much less costly to develop.

Several issues in the choice of an inflation treatment must still be addressed. One is whether the inflation measure should be *expressly* designed to track utility industry input price inflation. There are several precedents for the use of utility-specific inflation measures in MRP rate escalation mechanisms. Such a measure was used in one of the world's first large scale MRPs, which applied to U.S. railroads. Such measures are also popular in Canada. They are currently used in MRPs for western railroads and for energy utilities in Alberta, British Columbia, and Ontario.[27] The trend in the inflation indexes for Canadian energy utilities is typically a weighted average of the trends in a provincial labor price index and a gross domestic product

[27] The volume related composite price index for western railroads is discussed at www.otc-cta.gc.ca/eng/ruling/120-r-2015.

implicit price index ("GDP-IPI"). The weights assigned to the two subindexes has been an important issue in the MRP proceedings.

Notwithstanding such precedents, the majority of rate indexing plans approved worldwide do not feature industry-specific input price indexes. They instead feature measures of macroeconomic (economy-wide) price inflation. Gross domestic product price indexes ("GDPPI's") have most commonly been used for this purpose in North American MRPs.

Macroeconomic inflation measures have some advantages over industry-specific measures in rate adjustment indexes. One is that they are available, at little or no cost, from government agencies. There is then no need to go through the chore of annually recalculating complex indexes. The sizable task of choosing an industry-specific price index is also sidestepped. The design of a capital price for such an index can be especially controversial. Customers are more familiar with macroeconomic price indexes (especially CPIs).

When a macroeconomic inflation measure is used the X factor must be calibrated in a special way if it is to reflect industry cost trends. Suppose, for example, that the inflation measure is a GDPPI. In that event we can restate the revenue per customer index in [11c], for example, as

$$\textit{growth Revenue/Customer} = \textit{growth GDPPI} - [\textit{trend MFP} + (\textit{trend GDPPI} - \textit{trend Input Prices}) + \textit{Stretch Factor}] \quad [14]$$

It follows that an ARM with a GDPPI as the inflation measure can still conform to index logic provided that the X factor effectively corrects for any tendency of GDPPI growth to differ from industry input price growth.

Consider now that the GDPPI is a measure of inflation in the economy's *output* prices. Due to the broadly competitive structure of the economy, the long run trend in the GDPPI is then the difference between the trends in input prices and MFP indexes for the economy.

$$\textit{trend GDPPI} = \textit{trend Input Prices}^{\textit{Economy}} - \textit{trend MFP}^{\textit{Economy}}. \quad [15]$$

Provided that the input price trends of the industry and the economy are fairly similar, the growth trend of the GDPPI can thus be expected to be slower than that of the industry-specific input price index by the trend in the economy's MFP growth. When the economy's MFP growth is rapid this difference can be substantial. When a GDPPI is the inflation measure, the ARM therefore already tracks the input price and MFP trends of the economy. X factor calibration is warranted only to the extent that the input price and productivity trends of the utility industry differ from those of the economy.

Relations [14] and [15] can be combined to produce the following formula for a revenue per customer escalator.

growth Revenue/Customer = growth GDPPI -

$$\begin{bmatrix} \left(\text{trend } MFP^{Industry} - \text{trend } MFP^{Economy}\right) \\ + \left(\text{trend Input Prices}^{Economy} - \text{trend Input Prices}^{Industry}\right) + \text{Stretch} \end{bmatrix} \quad [16]$$

This formula suggests that when a GDPPI is employed as the inflation measure, the revenue per customer index can be calibrated to track industry cost trends when the X factor has two calibration terms: a "productivity differential" and an "input price differential". The productivity differential is the difference between the MFP trends of the industry and the economy. X will be larger, slowing revenue growth, to the extent that the industry MFP trend exceeds the economy-wide MFP trend that is embodied in the GDPPI.

The productivity differential is less of an issue in Canada than in the United States because the multifactor productivity trend of the Canadian economy is typically close to zero. The productivity differential would thus effectively be the productivity trend of the utility peer group.

The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry. The input price trends of a utility industry and the economy can differ for several reasons. One possibility is that prices in the industry grow at different rates than prices for the same inputs in the economy as a whole. For example, labor prices may grow more rapidly to the extent that utility workers have health care benefits that are better than the norm. Another possibility is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. It is also possible that the industry has a different mix of inputs (e.g., more capital inputs) than the economy.

The complexity of input price differential calculations can be sidestepped with an industry-specific input price index. This is likely a major reason why industry-specific indexes have been favored by Canadian regulators. However, controversy will still be encountered concerning the design of such indexes, most notably over index weights.

5. Other Plan Design Issues

5.1 Cost Trackers

5.1.1 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. Recovery of these costs is then typically initiated promptly using tariff sheet provisions called riders. Some trackers pass through the costs to customers, while others adjust rates for the variance between these costs and placeholder amounts already in rates. The cost may, alternatively, be treated as a regulatory asset earning interest and considered for inclusion in the revenue requirement in future rate cases.

While tracked costs are usually subject to some form of prudence oversight, prompt recovery of costs deemed prudent (or their delayed recovery with interest) weakens the incentive to contain them. This in turn weakens the incentive to pursue CDM that constrains these costs. Tracked costs can account for a large portion of a customer's bill.

On the other hand, cost trackers reduce utility operating risk because revenue tracks cost growth more closely. This can make it easier for utilities to operate under MRPs. Some costs are hard to address using ARM provisions of MRPs.

Consider also that the weak incentive to contain tracked costs has some upside where efficiently incurred costs merit encouragement. For example, we have noted that utilities have a disincentive to embrace CDM solutions to the extent that they slow rate base growth. PIMs for CDM (discussed further below) and MRPs typically don't fully replace this disincentive with positive incentives. Tracking CDM-related costs improves the balance of incentives for utilities to pursue CDM.

In summary, cost trackers are the "swing man" of utility regulation, finding uses even in MRPs. Their use in MRPs should nonetheless be carefully limited. Where the weakened cost containment incentives engendered by conventional trackers are nonetheless a concern, methods are available to incentivize tracked costs:

- Tracked costs can be subject to special oversight. The reduction in rate cases that MRPs make possible frees up resources to review these costs.
- Cost trackers can be incentivized. For trackers that base revenue on forecasted cost, one common approach is to make less than 100 percent true ups to actuals. Deviations from forecasts need not be treated symmetrically. For example, a hard cap on overspends can be combined with 50/50 sharing of underspends.

5.1.2 Capital Cost Trackers

Introduction

Capital cost trackers compensate utilities for the annual costs (e.g., depreciation, return on asset value, and taxes) that targeted capex gives rise to. They are sometimes used in MRPs to address capital cost surges that are difficult to address with an ARM. The capital cost of utilities is typically less volatile than O&M expenses. However, surges in capex are sometimes necessary. For example, utilities occasionally build large power plants and/or sizable new transmission lines. "Lumpy" investments may produce capacity that is initially in excess of current requirements. Rate shock can occur when such assets enter the rate base. If there is then a lull in major plant additions, depreciation of the new assets can halt or reverse overall rate base growth. The end result is a "stairstep" cost trajectory.

Capex surges are less common in energy distribution than in generation or transmission. The reason is that distribution systems tend to grow more gradually as settlement of the area they serve expands. Capex is incurred each year to extend service to new shopping malls, residential subdivisions, and industrial establishments. Replacement of aging facilities is also typically spread out over time for similar reasons. Unless the number of customers served is declining, distribution systems for this reason tend to experience comparatively steady rate base growth.

The difference in the cost trajectories of energy distributors and vertically integrated electric utilities is reflected in the design of MRPs used in their regulation. Since the cost trajectories of distributors are more steady and predictable, it is easier to agree on a multi-year trajectory of steady rate or revenue requirement escalation. It is more difficult for parties to agree on a path of gradual rate escalation for a vertically integrated utility that makes major plant additions intermittently.

Some energy distributors have nonetheless experienced periods of unusually high capex that cause capital cost to surge. Common triggers have included the construction of a large gas transmission line or storage field (investments that materially redefine or expand the utility's mission); the rapid build out of advanced metering infrastructure or other "smart grid" technologies; changes in the reliability and safety standards of government agencies; and the need to catch up on replacement investment after many years of operating under MRPs.

MRPs do not always contain provisions to buffer utilities from the full earnings impact of capex surges. There are several reasons for this. Note first that MRPs may be reasonably designed to provide the opportunity for efficient utilities to earn their allowed return *over the course of several years* rather than *in each and every year.* A utility might suffer lower earnings early in the plan period that are offset by higher earnings in later plan years (or vice versa). Although less desirable, a utility might under earn in one MRP but make it up with higher earnings in later plans (or vice versa).

A second consideration is that a surge in capex often is followed by several years of slow capital cost growth as the new capital starts to depreciate. Adjustments to O&M are another tool in the distributor's strategy kit. A one dollar permanent reduction in real O&M expenses finances more than ten dollars of capex. Some kinds of capex are partially self-financing due to the O&M savings they produce. Noteworthy examples include advanced metering infrastructure and the replacement of cast iron and bare steel mains.

Another strategy for avoiding under earning from high capex is to trim the capex budget to better fit the funding available. Capex is often deferrable without short term impairment of safety and reliability. It may, for example, be possible to spread out a program of replacement investment over fifteen years rather than five if the utility carefully prioritizes investments and does first those that affect safety and reliability the most. A step up in replacement capex can be delayed to start in the last years of an MRP or the first year of the next MRP.

When capex projects are undertaken, a search for economies is essential. A cost-minimizing balance must be struck between O&M and capex. In capital-intensive businesses like energy transmission and distribution, containment of capex is a key to good cost management and customer value.

Our analysis suggests that for a distributor that does not have unusual capex needs, a well-designed index-based ARM should be sufficient to finance normal capex requirements on average over many years. The budgets yielded by the ARM may be too small in some years but will be too large in others. This mirrors the outcome of competitive markets where, for example, an aluminum smelter cannot count on higher aluminum prices in the years immediately following an increase in its capacity.

Cumulative Revenue Escalation Caps

One way to address necessary capex surges is to give utilities some flexibility in the timing of their rate escalations. For example, utilities may be restricted only with respect to the *cumulative* pace of revenue per customer growth during the plan period. If it is allowed 8% revenue per customer growth over a four year period, for instance, it may take all 8% growth in one year to finance a "lumpy" investment provided that it "makes do" with 0% revenue/customer growth in the other three years. It is possible to extend this flexibility to multiple plans.

Ratemaking Treatments of Tracked Costs

The efficiency of tracked costs is a critical concern of regulators in approving a capital cost tracker. Trackers weaken capex containment incentives to the extent that they ensure recovery of a utility's cost rather than providing a reasonable budget that may vary from actual cost. In an MRP where other costs (e.g., O&M expenses) are not subject to tracker treatment, a passthrough of targeted capex cost can create a perverse incentive to increase this capex so as to reduce untracked costs.

One way for regulators to contain the incentive problem is to limit the kinds of capex eligible for tracking. Ideally, most of a utility's cost is not tracked and the tracker strengthens the incentive to contain these costs by reducing the frequency of rate cases. The ratemaking treatment of eligible capex can also discourage excess. Plant addition budgets are usually set in advance and Commission review of these budgets can be quite extensive, as we discuss further below. Once a budget is established the treatment of variances from the budget arises becomes an issue. Some capital cost trackers return capex underspends to ratepayers promptly. As for overspends, some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (e.g., 50-50) between the utility and its customers. These sharing mechanisms sometimes apply to underspends as well as overspends.

Appraising the Need for Trackers

A key issue in the approval of a capital cost tracker is the need for tracking. This decomposes into two issues, the need for high capex and the need for tracking the capex. We address each issue in turn.

Ascertaining the Need for Higher Capex Ascertaining the need for high capex in a proceeding considering capex trackers can be challenging, as it is in a forward test year rate case. Capex trackers for energy distributors sometimes address the cost of accelerated system modernization. The need for a particular plan of modernization can be especially challenging to appraise compared to the need for other kinds of capex surges that are commonly tracked such as those for new generation capacity or emissions control facilities. Distribution modernization plans involve a measure of discretion, and the regulatory community does not always have much expertise in appraising them. Generation plant additions also involve some discretion, but regulators of vertically integrated utilities have years of experience considering the need for new generation. Integrated resource planning and a certificate of public convenience and necessity ("CPCN") are often required before construction can proceed. There are competitive alternatives to expanded self-generation and proponents of these alternatives are often aggressive in pressing their cases in these hearings.

In this section best practices in the preparation of distributor evidence supporting a capital cost tracker are discussed. Where possible, references to decisions provided by regulators are provided.

Minimum Filing Requirements Utilities seeking capital cost trackers are often subject to minimum filing requirements ("MFRs"). These requirements sometimes extend beyond the submissions needed to support a specific tracker to include an occasional "foundational filing" on the company's multiyear capex plan. To the extent that they are prepared and reviewed professionally, foundational filings can reduce the scope of subsequent prudence reviews. Annual capex subject to tracker treatment can subsequently be determined through annual filings and need not follow the exact plan laid out in the foundational filing if sufficient justification is provided. Foundational filings may be updated during the term of the capital cost tracker to account for updated economic conditions and changes in the plans. Representative minimum filing requirements from New Jersey are presented in the Appendix.

An argument can also be made for pre-screening foundational filings. In California, the entire general rate case applications of utilities must be pre-screened months in advance of the filing date to ensure that all required items have been provided. The California Public Utilities Commission ("CPUC") extended this requirement to capital trackers in a March 2013 order approving most of the smart grid pilots proposed by Pacific Gas & Electric ("PG&E"). In its decision the CPUC found that

> While we were able to review the pilots requested in this application, we found PG&E did not always provide sufficient details. In order to improve the quality of future applications, we direct PG&E to present future Smart Grid proposals to staff and other stakeholders and receive feedback prior to filing an application. We also direct PG&E to ensure that future proposals include more details on schedules, the EM&V processes, and cost and benefit estimates."[28]

Independent Studies An independent study of projects proposed for cost trackers is desirable, particularly an assessment of various options. The opinions of engineers are especially welcome in the appraisal of accelerated modernization programs.

Other Evidentiary Guidelines Here are some other useful guidelines concerning the evidence of need for capital cost trackers.

- Competitive bidding and the presentation of evidence by competitors is a common feature of hearings to consider CPCNs for generation plant additions. This kind of evidence can also be pertinent in proceedings to review transmission and distribution system capex. By providing evidence of bidding, a utility's case for prudence is encouraged as they have shown that there was an effort to minimize costs.
- Metrics for quantifying the benefits of system modernization projects are useful. These may include, but are not limited to SAIDI and SAIFI improvement (or non-degradation), O&M cost savings, other cost savings, reduction in employee injuries or

[28] California Public Utilities Commission (2013), In the Matter of the Application of Pacific Gas and Electric Company for Adoption of its Smart Grid Deployment Project (U39E), Decision 13-03-032, p. 71.

injuries to others, reduction in length of time to respond to customer calls, reduction in the number of estimated or incorrect customer bills, etc.

Ascertaining the Need to Track Higher Capex The task of ascertaining the need to track the cost of high capex is somewhat simplified under traditional regulation. If a utility is already filing rate cases fairly frequently, and sometimes underearns, high capex is likely to impose additional attrition, making rate cases even more frequent, and possibly annual. Under these conditions, a tracker for the cost of a capex surge is quite likely to reduce rate case frequency without much concern about over earning.

Analysis of the need for a capital tracker can be more complicated when a utility will be operating under an MRP with an ARM that provides automatic rate increases. The ARM provides some compensation for cost growth. Moreover, the MRP should strengthen the performance incentives of subject utilities and thereby trigger some acceleration in their productivity growth that can help to finance capex. There is thus an increased risk that the tracker will trigger over earnings.

An MRP with a stairstep or hybrid ARM is of somewhat less concern in this regard since the kinds of capex that go into the capital cost forecast are often well known, and it is easier to establish that new kinds of capex need separate funding. Suppose, however, that the ARM is index-based and the X factor is calibrated to reflect the historical MFP trend of a peer group. Since power T&D have a capital-intensive technology, the MFP trend is quite sensitive to the growth in the capital quantity. In a multifactor productivity study used for X factor calibration, the calculation of the capital quantity trend typically includes all capex. This raises a concern that the addition of the capex tracker will lead over time to double charges for the same investments.

The issue of double charges has two dimensions. One is whether double charges are likely to occur during the plan period. The other is whether double charges are likely to occur between plan periods. A utility might, for example, be compensated for a necessary surge in replacement capex that reduces the need for replacement capex in subsequent periods. It will nonetheless be difficult to establish in later plans that an X factor based on the long run TFP trend is overcompensatory.

Ratemaking Treatment of Other Costs

Another important issue that arises in a proceeding considering a capital cost tracker is the ratemaking treatment of other costs. Separate recovery of certain capex costs means that the cost of the residual capital rises more slowly, and perhaps also more predictably. As the share of capex costs flowing through trackers rises, the growth of residual capital cost slows further. If *all* capex cost flows through trackers the residual capital cost is certain to *decline*. Additionally, the productivity growth of O&M expenses sometimes exceeds that of capital. For these reasons, capex trackers with broad-based eligibility guidelines often coincide with utility commitments to multiyear rate *freezes*.

To the extent that the capex excluded from indexing is sizable and involves the normal kinds of capex undertaken by sampled utilities, it may be necessary to raise the base productivity factor in the rate escalation mechanism that compensates the utility for other costs. A higher X may be needed in succeeding plans as well as the current plan.

Since X factor adjustments of this kind clearly complicate design of index-based rate escalation mechanisms, expedients should be considered. One idea is to keep the capital costs of certain large projects outside of the indexing mechanism *in subsequent plans* if they are excluded from the plan under consideration. This will tend to slow the company's future revenue growth because the rate base associated with the capex is sure to decline in subsequent plans.

Capital Cost Tracker Precedents

There are numerous precedents for capital cost trackers for gas, electric, and water utilities in the United States. The popularity of capital trackers in US utility regulation reflects in part the generally more conservative approach to regulation in US jurisdictions.

- Most capital trackers in North America are not embedded in MRPs that have ARMs to provide automatic rate escalation for cost pressures.
- Many of these trackers are approved in jurisdictions that do not have fully forecasted test years. Many US jurisdictions still have historical test years.
- The declining average use of their product which gas and water distributors often experience harms their ability to self-finance capex. Some of the distributors with

capex trackers are not protected from this problem by revenue decoupling or high customer charges.

In the context of such conservative regulation, capital cost trackers are perceived by regulators as a way to reduce the frequency of rate cases by "chipping away" at the problem of financial attrition instead of undertaking more sweeping changes in the regulatory system. Thus, the fact that numerous trackers have been approved in the United States does not by itself imply that trackers are usually needed in the design of an MRP.

It is also interesting to examine the kinds of capex that are typically made eligible for tracking in the States. On the electric side, trackers for emissions controls, generation capacity, and advanced metering infrastructure account for the vast majority of trackers approved in recent years. ~~Apart from the metering precedents, only a few trackers have yet been approved for programs to modernize power distribution systems.~~ Most capex trackers for gas utilities address the cost of accelerated programs for replacing cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges, are also common today for accelerated modernization.

It is also noteworthy that several approved trackers recover capital costs *net of any O&M cost savings.* This ratemaking treatment has been used for advanced metering infrastructure and the replacement of cast iron and bare steel mains.

Capital cost trackers are occasionally incentivized. In California, for example, Southern California Edison and San Diego Gas & Electric had advanced metering infrastructure trackers involving preapproved multi-year cost forecasts. Each company was permitted to recover 90 percent of prudent overspends of the cost forecast up to a cap, and San Diego Gas & Electric was permitted to keep 10 percent of underspends.

5.2 Relaxing the Revenue/Usage Link

Regulators are increasingly interested in relaxing the link between a utility's revenue and use of its system by customers. Two methods are widely used in North America for effecting this relaxation: lost revenue adjustment mechanisms ("LRAMs") and revenue decoupling. We discuss each approach in turn.

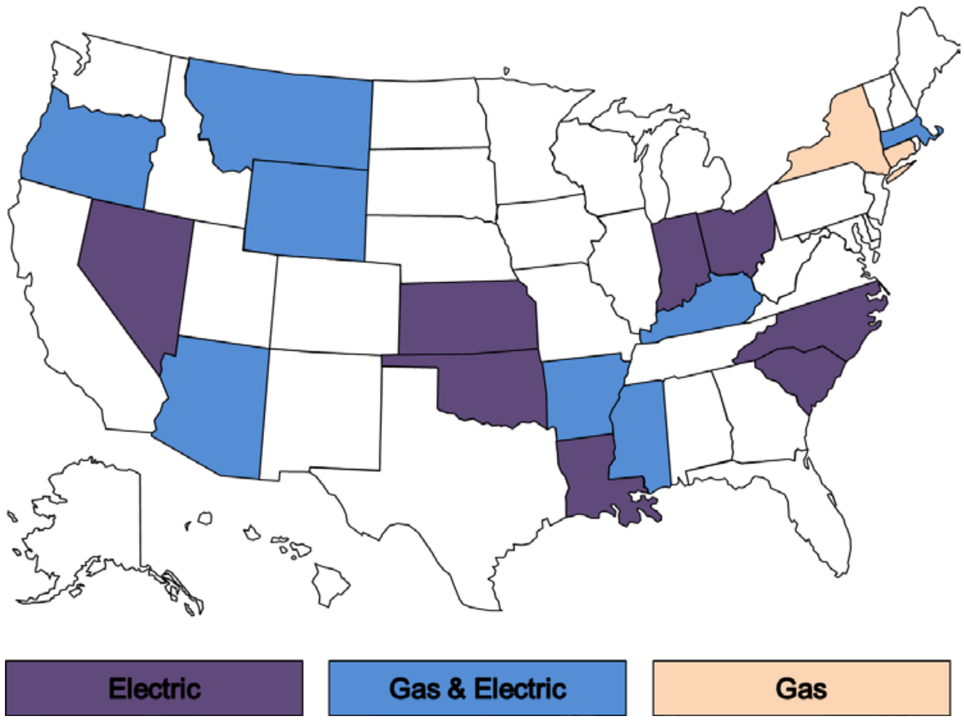
5.2.1 LRAMs

LRAMs explicitly compensate utilities for short-term losses in base rate revenues due to their CDM programs. Compensation is usually effected through a special rate rider. Estimates of load losses are needed.

LRAMs reduce the disincentive for utilities to embrace DER solutions that are eligible for LRAM treatment. They do not compensate utilities for effects of external forces, like CDM programs managed by third parties, which slow load growth. Estimates of load savings from utility CDM can be complex and are sometimes controversial. The scope of CDM initiatives addressed by LRAMs is therefore frequently limited to those for which load impacts are easier to measure. The utility remains at risk for revenue fluctuations in volumes and peak load due to weather, local economic activity, and other volatile demand drivers. Utilities are thus exposed to the risk of usage charges that encourage CDM but make revenue sensitive to demand volatility.

The Ontario Energy Board permits LRAMs for power distributors. US precedents for LRAMs are detailed in Figure 4 below. It can be seen that they are quite popular for electric utilities. LRAMs are less popular for gas distributors since the declining average use they have experienced is due chiefly to external forces like improved furnace efficiency that LRAMs don’t address. Some utilities have LRAMs for some services and revenue decoupling for others. In New York, for example, some natural gas distributors have decoupling for residential and commercial customers and LRAMs for some large load customers.

Figure 4: Recent LRAMs by State



5.2.2 Revenue Decoupling

Revenue decoupling adjusts a utility's rates periodically to help its actual revenue track its allowed revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism. The RDM tracks variances between actual and allowed revenue and adjusts rates on a regular schedule to reduce them. The revenue adjustment mechanism escalates allowed revenue to provide relief for cost pressures.

<u>Revenue Decoupling Mechanisms</u>

RDMs can make true ups annually or more frequently. More frequent adjustments cause actual revenue to track allowed revenue more closely so that rate adjustments are smaller. The size of the rate adjustments that is permitted in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be recovered immediately. A "hard" cap does not.

RDMs vary in the scope of utility services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue and are often the primary focus of CDM programs. RDMs also vary in terms of the service classes for which revenues are pooled for true up purposes. In some plans all service classes are placed in the same "basket". Other plans have multiple baskets, and these insulate customers of services in each basket from changes in revenue for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between allowed revenue and weather normalized actuals. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism.

RDMs raise anew the issue of cross subsidization by creating a new potential path for discounts offered to one service class to be recovered from other service classes. A discount can reduce actual revenue relative to allowed revenue, and the revenue shortfall must somehow be recovered. Concern about cross subsidies can be limited with carefully chosen decoupling service baskets. For example, large volume customers can be placed in a different basket from small volume customers. Alternatively, the ability to offer discounts can be limited.

Decoupling/Revenue Cap Systems

Price caps can in principle apply to some service classes while revenue caps apply to others. In this event, revenue decoupling is not a route by which discounts to one service class can be recovered from other classes. Furthermore, the price caps can be designed so that discounts to some price cap customers cannot be recovered from other price cap customers.

Revenue Adjustment Mechanisms

The great majority of decoupling systems have some kind of revenue adjustment mechanism since, if allowed revenue is static, the utility will experience financial attrition as its costs inevitably rise. The more important issue in a proceeding to consider decoupling is therefore the design of the revenue adjustment mechanism rather than the need for one. Most revenue adjustment mechanisms approved in the United States escalate allowed revenue only for customer growth. As noted in Section 4, escalation for customer growth is sensible because customer growth is an important driver of distribution cost and is highly correlated with other important cost drivers such as peak delivery capacity.

Decoupling Advantages

Revenue decoupling eliminates the lost revenue disincentive for a wide array of utility initiatives to encourage CDM, without requiring load impact calculations or rate designs with high fixed charges that discourage CDM. To the extent that recovery of allowed revenue is ensured, utilities can use rate designs with usage charges more aggressively to foster efficient CDM. The boost to CDM solutions that decoupling provides makes environmental intervenors strong supporters of decoupling in the United States. Controversy over billing determinants in rate cases with future test years is reduced.

States that have tried gas and electric revenue decoupling are indicated on the maps below in Figures 5a and 5b, respectively. Decoupling is the most widespread means of relaxing the revenue/usage link of gas distributors. This reflects the fact that gas distributors often experience declining average use and that this has been due chiefly to external forces. In the electric utility industry, decoupling has been favored in states that strongly support CDM.

Figure 5a: Electric Revenue Decoupling by State

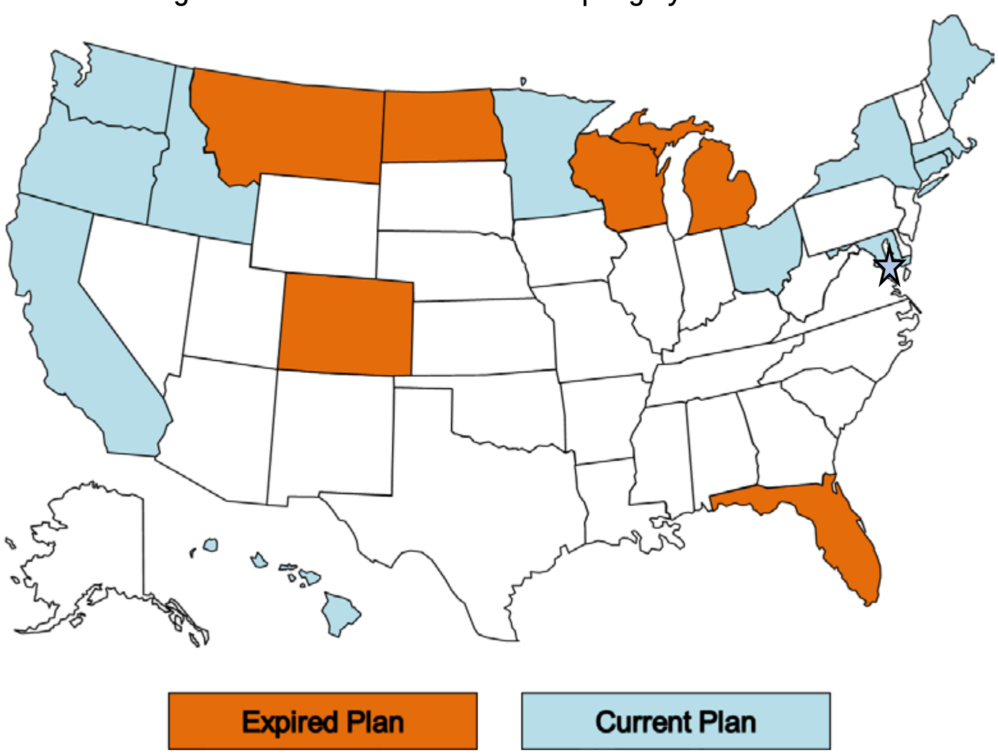
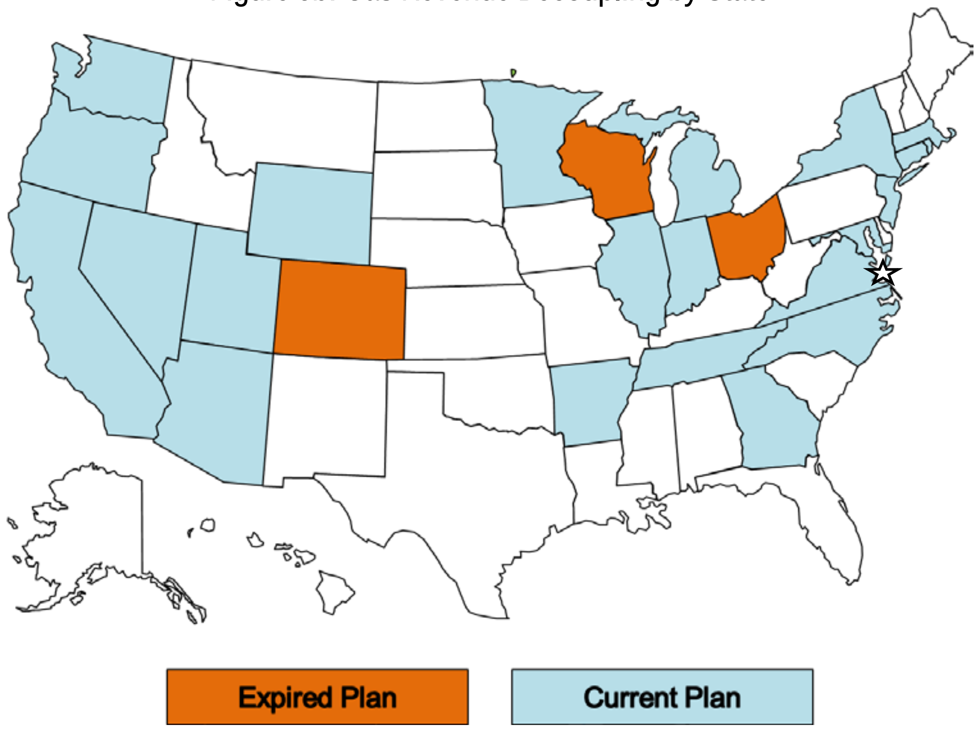


Figure 5b: Gas Revenue Decoupling by State



5.3 Performance Metric Systems

5.3.1 The Basic Idea

Performance metrics (called “outputs” in Britain) quantify utility activities that matter to customers and the public. These metrics alert utility managers to key concerns, target areas of poor (or poorly incentivized) performance, and can reduce the cost of oversight. Metrics that are closely linked to the welfare of customers and the public include utility cost, and service quality. A familiar example of such metrics is the system average interruption duration index (“SAIDI”), which measures an aspect of service reliability. There is also an interest in “intermediate” metrics that are closely associated with the variables of ultimate interest. These include the MWh and peak MW of load.

In a performance metric system, target (aka “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. This is typically done by taking the differences or ratios between the values. Performance appraisals can focus on the *level* of metric or its *trend*.

Quantitative performance appraisals using metrics are sometimes used in ratesetting. A utility’s revenue is then linked explicitly to its measured performance. Appraisals can, for example, be used in rate cases to help set the revenue requirement. Rates can be adjusted *between* rate cases to reflect performance appraisals using **targeted performance incentive mechanisms** (“**PIMs**”).

A PIM improves performance incentives by providing awards and/or penalties based on performance measurements using metrics. The following simple PIM for a hypothetical utility called Eastern Lighting is one example of how a PIM can be designed.

$$\textit{Revenue Adjustment}^{Eastern} = \$ \times (SAIDI^{Eastern} - SAIDI^{Target})$$

Here, SAIDI is the performance metric. The SAIDI value attained by Eastern is compared to a target. The term “$” is the award/penalty rate per unit of deviation from the target. If Eastern meets the target, then $SAIDI^{Eastern}$ equals $SAIDI^{Target}$ and the revenue adjustment is zero. If Eastern performs better than the benchmark, the company may increase its revenue. By the same token, if Eastern underperforms it must decrease its revenue.

Targets that provide a realistic stretch goal for the utility can be difficult to establish. Targets should, after all, properly reflect circumstances utilities can’t control. The cost of a power distributor will, for example, depend on local input prices, the number of customers served, peak demand, and the extent of system undergrounding. The full set of business conditions that “drive” a metric and their relative importance is often unclear.[29]

Consideration of conditions that influence the *level* of a metric can be sidestepped by making the *trend* in its value the focus of the performance appraisal. A PIM could, for example, focus on the improvement in a utility’s cost performance, and not address whether the initial level of cost was efficient. Of course, the trends in performance metrics over time can also be influenced by business conditions. A focus on trends is thus especially convenient when there is not much reason for the target to change over time. PIMs for reliability, for instance, typically use the utility’s recent average historical value of the metric as the target.

Statistical research can inform the selection of metrics and targets using data on the operations of other utilities (aka “peers”). Statistics have been extensively used to benchmark costs, and statistical benchmarking of reliability is improving. Extensive data are available from

[29] In the future, cost benchmarking will be further complicated by inter utility differences in the penetration of distributed generation.

the Federal Energy Regulatory Commission ("FERC") and other public sources in the United States which are useful in utility cost and reliability benchmarking.

Statistics can be used in several ways to develop metrics and targets. One approach is to develop an econometric model that explains the relationship of cost to various business conditions. Model parameters are estimated using econometric software and historical data on utility operations. Econometric results can be used to guide selection of an appropriate peer group. Given econometric parameter estimates and local values for the business condition variables, the model can, alternatively, predict the value for the utility and this can be used as the benchmark. A cost benchmark for Eastern Lighting might, for example, be predicted using the following model,

$$\begin{aligned} Cost^{Eastern} = a_0 + a_1 \textit{Input Price Index}^{Eastern} + a_2 Customers^{Eastern} + a_3 \textit{Line Miles}^{Eastern} \\ + a_4 \textit{Pervasiveness of Undergrounding}^{Eastern} \ldots \end{aligned}$$

The terms a_0, a_1, . . . in this model are the parameter estimates.

Simpler methods are also available and have to date been more widely used in benchmarking. If one business condition is considered to have a particularly important impact on a metric, it is common to recalculate the metric to achieve some rough control for its effect. SAIDI, for example, is the ratio of the total duration of the outages experienced by customers to the total number of customers. Similarly, statistical research reveals that the number of customers is also an important driver of power distributor cost. One might, then, use cost per customer as a cost performance metric for such utilities.

Statistical research can also be used to design PIMs for *trend* metrics. Since input price inflation and customer growth are largely beyond a power distributor's control, the growth in an index of the power distributor's productivity is a sensible performance metric. This can be compared to the growth in the productivity indexes of similarly-situated peers.

Award/penalty rates play a key role in the incentive impact of PIMs and the sharing of benefits between the utility and customers. Appropriate rates can also be difficult to calculate. Calculation is relatively simple for utility cost metrics, since rates need only be calibrated to share the measured benefits of cost performance between the utility and its customers. Award/penalty rates for load metrics must, in contrast, additionally reflect their likely impact on cost. Award/penalty rates for reliability or other dimensions of service quality should reflect the value of service to customers or the incremental cost of improving quality.

5.3.2 Cost PIMs

Gas Procurement

The most common use of cost PIMs in the United States has been in the regulation of the gas procurement operations of natural gas distributors. Gas procurement expenses are almost always subject to cost tracker treatments. PIMs have been used to strengthen cost containment incentives and simplify regulatory oversight. A typical PIM for gas procurement features a benchmark for the unit cost (e.g., cost/Dkt) of gas supply. The benchmark is usually tied to market prices in gas fields, and may also reflect the unit cost of gas transportation.

General Cost

PIMs for general cost management are fairly rare. PIMs for rates charged by utilities have been added, however, to several formula rate plans. Performance incentives are weak in these plans, which otherwise resemble cost plus regulation.

Cost benchmarking studies are rarely filed in US rate cases and have almost never triggered revenue adjustments. US regulators are more likely to commission management audits when they have concerns about cost or outage management. Benchmarking evidence is occasionally filed voluntarily by utilities in rate cases. Oklahoma Gas & Electric and Public Service of Colorado have, for example, filed econometric studies of their costs in several recent rate cases.[30] The Public Service studies are unusual for having benchmarked the company's forecast of test year cost.

Statistical cost benchmarking plays a more prominent role in utility regulation in Ontario and in numerous countries overseas. Econometric methods have been favored for these studies in the English-speaking world. Econometric benchmarking studies filed in rate cases have

[30] Mark Newton Lowry, David Hovde, Blaine GIlles, and John Kalfayan, *Recent Cost Performance of Oklahoma Gas & Electric*, Exhibit No. MNL-2 in Oklahoma Corporation Commission Cause PUD 201100087, July 2011. Report Prepared for Oklahoma Gas & Electric.
Mark Newton Lowry, David Hovde, John Kalfayan, Stelios Fourakis, and Matt Makos, *Benchmarking PS Colorado's O&M Revenue Requirement*, Exhibit No. AKJ-2 in Colorado Public Utilities Commission Docket 14AL-0660E, June 2014. Report Prepared for Public Service Company of Colorado.

focused on various kinds of cost including O&M expenses, "totex" (the sum of O&M and capital expenditures), and total cost (the sum of O&M expenses, depreciation, and return on plant value).

The California Public Utilities Commission for many years required utilities to file evidence of their multifactor factor productivity ("MFP") trends in rate cases. A commission staff member had expertise in this area. However, most utilities did not file studies that were useful in appraising cost performance and the requirement was ultimately rescinded.

5.3.3 Service Quality PIMs

The Basic Idea

Traditionally, service quality PIMs were needed to balance the cost-quality tradeoff that utilities experience. In early MRPs there was often a concern that companies would cut cost at the expense of customer service quality. Service quality PIMs for electric utilities fall into two general categories: reliability PIMs and customer service PIMs.[31]

Power Distribution

Reliability PIMs for power distributors fall into three general categories: system reliability, system restoration, and granular reliability metrics. The most common system reliability metrics are SAIDI, system average interruption frequency index ("SAIFI"), and customer average interruption duration index ("CAIDI"). SAIDI and SAIFI measure the reliability of all customers while CAIDI measures the duration of outages for all customers that have an outage. All of these metrics are based on the number and duration of "sustained interruptions," which are defined as an interruption longer than the minimum amount of time determined by individual regulators, often 1 or 5 minutes.[32] In order to better assess a company's reliability performance, regulators have often allowed utilities to exclude major event days, which are supposed to be relatively rare and are in large measure outside of the utility's control. Some

[31] See Larry Kaufmann, Lullit Getachew, John Rich, and Matt Makos, *System Reliability Regulation: A Jurisdictional Survey*, report prepared for the Ontario Energy Board and filed in OEB Case EB-2010-0249, May 2010, for a survey of reliability PIMs. See Larry Kaufmann, *Service Quality Regulation for Detroit Edison: A Critical Assessment*, Michigan PSC Case No. U-15244. Report prepared for Detroit Edison and Michigan Public Service Commission Staff, March 2007, for a survey of customer service PIMs.
[32] Shorter interruptions may be measured through a metric called the Momentary Average Interruption Frequency Index ("MAIFI"), which is less commonly reported than SAIDI or SAIFI.

regulators also allow utilities to exclude outages from a variety of causes, including planned outages. Performance on these reliability metrics is often subjected to awards or penalties if specific targets are not met.[33]

Because regulators have allowed different exclusions for system reliability PIMs, comparisons between utilities have historically been difficult to make and assessing their performance on these metrics typically relied on comparisons between a utility's performance in the current year to its own historical performance, with good performance defined as maintaining or improving upon past reliability performance. In the past decade, the Institute of Electrical and Electronics Engineers ("IEEE") has adopted standard 1366 to standardize outage data by first standardizing the definition of the reliability metrics, the length of time required to qualify as a sustained interruption, and the methodology for determining major event days. This standardization has made it possible to compare reliability performance between utilities in recent years through econometric benchmarking. PEG has developed reliability benchmarking models for duration and frequency using standardized transnational data.

A second form of reliability PIMs focus on system restoration after major events. These metrics are much less common than the system reliability metrics and are more common in the US than in Canada. There may be different PIMs depending on whether the restoration is required for a major event or a regular outage. Performance on system restoration metrics may lead to financial penalties, but more often requires an explanation of poor performances.

System reliability PIMs can gloss over variances in service reliability experienced among customers. Some customers may suffer no interruptions while others experience 10 or more interruptions and be without service for days. This variance between customers has caused regulators to approve more granular reliability PIMs at multiple levels including operating regions, individual circuits, and even individual customers. At least 2 US utilities, Commonwealth Edison and Public Service of Colorado, have been required to report their service quality performance on a regional basis. Both companies have financial incentives for

[33] The Kaufmann, Getachew, Rich, and Makos (2010) report referenced above shows that at least 10 US states and 1 Canadian province have financial incentives tied to system reliability metrics.

their regional reliability performance, with Commonwealth Edison's targets requiring a 20% improvement in their SAIFI performance in 2 specific regions over a 10 year period.

Circuit PIMs often focus on the worst performing circuits and identify those groups of customers that experience the worst reliability. The definition of a worst circuit varies between regulators but often relies on a circuit's SAIDI or SAIFI performance. These PIMs may feature financial incentives, as well as a requirement that a utility provide a remediation plan for those circuits.

Customer specific reliability PIMs often report how many customers have been interrupted x or more times (e.g., customers experiencing multiple interruptions$_x$) and how many customers were interrupted for x or more hours (e.g., customers experiencing long interruption durations$_x$).[34] The value of x for these metrics is determined by the regulators. Some regulators may have the utility report multiple versions of the metric. For example, the Maryland regulator requires utilities to report the number of customers that experience 3 or more outages, 5 or more outages, 7 or more outages, and 9 or more outages.[35]

British and Australian regulators require utilities to pay customers if a customer has an excessive number of outages or is without service for an excessive amount of time. To receive these payments, customers often are required to file requests for payment along with evidence of their outages. Outside of Britain and Australia, customer-specific reliability PIMs do not typically have financial incentives. These PIMs have become increasingly popular in recent years, as Massachusetts has adopted a form of customers experiencing multiple interruptions and the Ontario Energy Board stated in a recent Report of the Board that it will introduce customer-specific reliability measures as soon as it is practical to do so.

Customer service PIMs encompass a wide array of metrics, including 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. Like reliability PIMs, performance on these metrics is often assessed through a comparison of a

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[34] See Larry Kaufmann and Matt Makos, *Customer Specific Reliability Metrics: A Jurisdictional Survey*, Report prepared for the Ontario Energy Board and filed in OEB Case EB-2010-0249, September 2013, for a survey of customer-specific reliability PIMs.
[35] Code of Maryland Regulations, 20.50.12.05.

company's current year performance to its recent historical performance. Because of a lack of standardization in the data and the effort required to process the available data, benchmarking a company's performance on customer service PIMs is very difficult.

Power Transmission

Appendix 7 of the Elenchus report highlights the output categories in the new British transmission price control plan called RIIO. These outputs are divided into five categories: safety, reliability and availability, customer satisfaction, connections, and environmental impact.[36] Each of these five categories has one or more metrics or incentive programs. The primary metrics and incentive programs for each output category are listed below:

- Safety: Compliance with the safety obligations set by the safety regulator
- Reliability & availability: Energy not supplied and the preparation and maintenance of a Network Access Policy
- Customer Service : Customer/stakeholder satisfaction survey and effective stakeholder engagement
- Connections: Timely connections and compliance with existing legal requirements
- Environmental: Sulfur hexafluoride leakage, business carbon footprint, transmission losses, visual amenity, environmental discretionary scheme

These metrics and incentive programs may have financial incentives, "reputational incentives", or no incentives. For example, there are no financial incentives tied to the primary safety and connections metrics, while energy not supplied, the customer/stakeholder satisfaction survey, and sulfur hexafluoride leakage performance are all tied to financial incentives. The business carbon footprint, transmission losses, and visual amenity programs all have reputational incentives. In at least one instance, for the development and maintenance of a Network Access Policy, a reputational incentive may be converted into a financial one at a later date.

[36] The Elenchus report listed a sixth category, social obligations, was not the subject of any requirements. An additional category, "wider works", was included as a secondary category. This category measures a company's performance at increasing additional transmission boundary transfer capacity.

5.3.4 PIMs for Conservation and Demand Management

The Basic Idea

PIMs can incentivize performance improvements that are specifically attributable to CDMs. Sensible performance metrics for such a PIM include the peak kW or kWh of load. In either case, the focus is typically on the *change* in the metric attributable to CDM.

The following load-related costs may be avoided with CDM and merit consideration in the design of such PIMs.

- Generation Fuel
- Purchased power (energy and capacity)
- Transmission
- Distribution (especially substations)

Net benefits are achieved from CDM when the change in these costs exceeds CDM expenses.

As an addition to decoupling or some other means for weakening the short-term link between base revenue and system use, PIMs for CDM can play a valuable role in incentivizing utilities to use CDM to slow rate base growth. Remarkably, this is true even if the PIM rewards the utility only for savings in *energy* expenses, because these expenses are tracked.

Disadvantages of PIMs for CDM include the following:

- As with LRAMs, the calculation of load savings from CDM is generally costly and can be controversial. Independent verification of savings has sometimes been required. PIMs for CDM therefore typically exclude many kinds of CDM programs. Utilities are incentivized to focus on programs that are addressed by the PIMs and may neglect or even oppose programs that aren't addressed.
- PIMs for CDM typically use load as the performance metric, when it is the costs that loads affect which ultimately matter. It can be difficult to calculate the utility cost savings that result from load savings.[37] The estimation challenge is especially great for costs that are largely fixed in the short-run, like those for T&D.

[37] The National Action Plan for Energy Efficiency notes on pages 6-12 of its useful 2007 document *Aligning Utility Incentives with Investment in Energy Efficiency*, that "the level of avoided costs is extremely important in determining energy efficiency program cost effectiveness and can be the subject of substantial debate.

Precedents

The 2014 survey of the Edison Foundation Institute for Electric Innovation found that PIMs for CDM are fairly common in the United States. In all, 29 states had some form of PIM, and an additional two states were evaluating the possibility. Among the states that had implemented PIMs, all but five had also adopted RDMs or LRAMs.[38] Among CDM PIMs, those focused on conservation programs are the most common, and some states have decades of experience with them. Some PIMs also incorporate demand response programs.

Some PIMs penalize utilities for failing to achieve approved load reduction targets. Whether or not penalties are possible, utilities are often rewarded for the estimated load reductions that they achieve. Rewards are typically contingent on attaining a threshold level of savings. The thresholds are sometimes below the savings targets. The targets are often expressed as a percentage of retail sales.

Rewards for CDM have been calculated in several ways. The most common approach is to grant utilities a share of the estimated net benefits from CDM. Since CDM expenses are often recovered by a cost tracker, this weakens the incentive to contain CDM expenses and this “shared savings” approach strengthens the cost containment incentive. Net benefits will typically be higher the higher are avoidable costs. Where rewards are linked to estimated benefits, the benefits considered are often restricted. Impacts on costs of base rate inputs like those for T&D are sometimes ignored. Impacts on the environment are frequently ignored. Another common approach is to pay a flat fee per MWh of energy saved. Some utilities are paid a lump sum for attaining savings targets.

Most PIMs for CDM approved to date have pertained to programs serving customers in scattered locations. However, a PIM recently approved for Consolidated Edison in New York addressed a project, called the Brooklyn Queens Demand Management Project, that used CDM to delay distribution system upgrades in a growing urbanized area of the service territory. An advantage of this approach is that distribution cost savings can be carefully estimated for a project of this type. A disadvantage is the high cost of estimation.

[38] Institute for Electric Innovation, State Electric Efficiency Regulatory Frameworks, December 2014.

5.4 Marketing Flexibility

5.4.1 Introduction

Many utilities believe they need flexibility in the rates and services they offer to realize the full potential value of their operations for shareholders and customers. Improved marketing can bolster earnings by increasing revenue and encouraging customers to use utility services in less costly ways. Incremental earnings from better marketing can be shared with customers. Customers also benefit from rate and service offerings more tailored to their needs.

The need for marketing flexibility is greater to the extent that demand for utility services is complex, changing, and sensitive to the terms of service offered. The elasticity of demand is greater for customers to the extent that they have alternative ways to meet their needs that are competitive with respect to cost and quality. Customers with few options and low demand elasticities are sometimes called “core” customers.

Marketing flexibility runs the gamut from greater commission effort to approve new rates and services by traditional means to “light handed” regulation and outright decontrol. Light handed regulation typically takes the form of expedited or interim approval of certain rate and service offerings. These offerings may be subject to further scrutiny at a later date (e.g., in the next rate case).

Flexibility is most commonly granted for rate and service offerings with certain characteristics. Key concerns of regulators include the impact of the offering on likely customers and on customers of other services that the utility offers. Generally speaking, flexibility is encouraged where new offerings are likely to benefit target customers and may benefit (or at least not harm) other customers.

Optional offerings have often been accorded expedited treatment because target customers are protected by their continuing access to service under closely supervised standard tariffs. One kind of optional offering is discounts from standard tariffs. Another is optional tariffs open to all qualifying customers. A third category is special (aka negotiated) customer-specific contracts. A fourth is new services. A fifth is discretionary services. A sixth is special service packages (which may include standard services as components). Marketing flexibility is also more likely to be granted for services to competitive markets.

Multiyear rate plans have long been used to regulate utilities where market-responsive rates and services are a priority. One reason is that less frequent rate cases reduce the regulatory cost of allocating the revenue requirement between a complex and changing mix of market offerings. They also reduce concerns about cross subsidies between service classes. These benefits of MRPs can be enhanced by designing other plan provisions in ways that insulate core customers from potentially adverse consequences of marketing flexibility.

MRPs can also strengthen utility incentives to improve marketing. For example, incentives can be strengthened to change rate and service offerings in ways that encourage customers to use their systems in less costly ways. To the extent that discounts can't be recovered from other customers, regulators are more confident of their prudence. MRPs can also be designed to strengthen incentives to promote use of utility services where this is deemed desirable.[39]

5.4.2 Railroad and Telecom Precedents

These benefits of MRPs help to explain their popularity in some industries. For example, telecom utilities were given a freer hand to offer competitive rates to customers in central business districts, where competition was greatest, and to offer value-added (aka discretionary) services, such as caller identification, that make use of new digital technologies. The reasoning behind this was that rates for *standard* services to residential customers were insensitive to such initiatives. For example, most telecom plans featured index-based price caps that separately escalated the prices of several service baskets. Rates for basic residential services were often frozen.

Under ratemaking reforms in the Staggers Rail Act of 1980, which included MRPs, U.S. railroads were also granted increased marketing flexibility. They used this flexibility to address intermodal competition from truckers and waterborne carriers, manage their costs better, and meet special customer needs. Lower rates were offered to customers making less costly service

[39] One means of accomplishing this is to exempt services meriting promotion from revenue decoupling.

requests. For example, special rates were offered for unit trains and pickups (and drop-offs) along dense traffic corridors.

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

5.4.3 Marketing Flexibility for Electric Utilities

Electric utilities have a longstanding need for flexibility in some of the markets they serve.

- Surplus generating capacity of utilities engaged in generation can be used to make sales in bulk power markets, and these markets are competitive and price-volatile. Underutilized T&D capacity has various uses in other markets. Land in transmission corridors, for instance, can be well-suited for nurseries, while distribution poles can carry cables of telecom and television service providers. Regulators have traditionally given electric utilities considerable flexibility in markets like these.
- Regulators have also accorded utilities some flexibility to offer special rates that encourage customers to make less costly service requests. The most common initiatives of this kind were, traditionally, optional interruptible rates to large volume customers. More recently, such customers have been offered various forms of optional dynamic pricing tariffs. These optional tariffs have usually required special approval.
- Large-load power customers often have relatively elastic demands for service because they have power-intensive technologies or options to cost-competitively cogenerate or operate at alternative locations, or are economically marginal. Customers of this kind loom larger in the finances of vertically integrated utilities. Special contracts for retail services to such customers are sometimes allowed, but these frequently require specific approval. Commission reviews of special contracts can take months.

Electric utilities today have increasing need for marketing flexibility. Advanced metering infrastructure makes it more cost-effective to offer time-sensitive and demand-charge pricing to all customers. Customers can be encouraged to reduce system use in hours when it is especially costly. Plug in electric vehicles are a new and power-intensive consumer technology that can reduce Canada's use of petroleum fuels. Advanced metering infrastructure, distributed storage, and other new distribution technologies open the door to many new value-added services, including premium quality services.

MRPs

MRPs have not yet played a large role in fostering electric utility marketing flexibility. One reason is that the majority of MRPs have applied to power distributors and these have less need for special pricing for large load customers. Another is that many MRPs for power distributors have decoupling provisions.

There are nonetheless examples of the use of MRPs to promote electric utility marketing flexibility. For example, the Maine Public Utilities Commission ("MPUC"), under the lengthy chairmanship of Thomas Welch (a former telecom industry lawyer), was for many years a leader in PBR for energy utilities. In the 1990s, Maine's electric utilities were still vertically integrated and needed flexibility in marketing power to paper and pulp customers, some of whom had cogeneration options and/or were economically marginal. The Maine legislature passed a law allowing the MPUC to authorize pricing flexibility plans whereby the utility can discount its rates with limited or no commission approval. The commission encouraged utilities to develop special contracts with customers.[40]

PBR (in the form of MRPs with index-based price caps) has been extensively used for electric utilities in Maine and its advantages in facilitating marketing flexibility have been recognized. In listing problems with traditional regulation that prompted it to promote PBR, the MPUC included in a 1993 rate case decision "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;

[40] The commission also permitted optional tariffs for special purposes such as space heating.

and 5) the general incompatibility of traditional, ROR ratemaking procedures with growing competition in the electric power industry”.[41]

The value of MRPs in facilitating better marketing was recognized by the commission. For example, they noted in approving an MRP for CMP in 1995 that

> 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. These features of the [MRP’s] pricing flexibility program simulate conditions in competitive industries and will help the Company adapt to increasing competition in its industry.

Marketing flexibility provisions were extensive in this plan and included the following.

- For existing customers, CMP was free to set rates between the rate cap and a rate floor estimate of long-term marginal cost.
- CMP would receive expedited approval of new targeted services. Rates for newly-created customer classes were capped at the rate of the class that the customer would otherwise have been in.
- CMP could also receive expedited approval of special rate contracts with individual customers. Different provisions applied for short term and long term contracts.

The MPUC used the fact that price caps encourage prudent market offerings to expedite the recovery of discounts in subsequent rate cases.

5.5 Efficiency Carryover Mechanisms

Several approaches are possible to the design of efficiency carryover mechanisms. Two design issues are salient.

1) How do we determine the value of efficiency gains or losses we wish to carry over?
2) How do we effect the carryover to the period following the plan?

We discuss each group of issues in turn.

5.5.1 Calculation of Efficiency Carryovers

One issue in the calculation of efficiency carryovers is the areas of performance that are considered for carryover. As one example, utility performance has a marketing as well as a cost

[41] MPUC, Order dated December 14, 1993. 1993 Me. PUC LEXIS 42.

containment dimension. Efficiency carryover mechanisms could, in theory, permit customers to keep some of the benefits from marketing efforts to boost capacity utilization. For a company operating under decoupling, however, there may be less interest in encouraging this kind of performance, and only *cost* efficiencies will be considered for carryover.[42] Regulators may also wish to focus on components of cost, such as opex and capex, over which utilities have a lot of control in the short run and ignore areas over which they have less control, such as the cost of older plant. Another consideration is the ease with which efficiency can be measured. It may be deemed easier, for example, to appraise opex efficiency than capex efficiency.

Still another consideration is the deferability of the costs subject to benchmarking. Replacement capital investments, for instance, can often be deferred for periods of five years or longer. Suppose, then, that a utility substantially underspends its capex budget in a rate plan by deferring replacement expenses and then asks for a budget for the same expenses in the next rate case. With a poorly designed efficiency carryover mechanism, it could receive a supplemental reward for this strategy that would not be popular with ratepayers.

These considerations are relevant in considering the merit of earnings as a measure of operating efficiency. An efficiency carryover mechanisms can permit the carryover of a part of the utility's share of surplus earnings, as calculated by an earnings sharing mechanism. To the extent that rates reflect current business conditions, high earnings could indicate good performance and low earnings bad performance. But rates may not properly reflect recent changes in business conditions. This leads to windfall gains and losses in the carryovers. Moreover, earnings reflect marketing as well as cost performance.

Once a cost category has been chosen for carryover there arises the issue of how to measure the efficiency meriting carryover. This is commonly done by comparing the cost in one or more recent historical reference years to a *benchmark*. In some PBR plans, the regulator has already determined by some means a specific revenue requirement for each year of the plan.

[42] Even in this case, the other operating revenues that are conventionally netted off of cost in the calculation of the revenue requirement may be worthy of consideration for efficiency carryovers.

Where this is so, the revenue requirement is itself a candidate benchmark, and is described as such in some rate plans that have efficiency carryover mechanisms.[43]

Where a revenue requirement for the cost in a particular year is not available, it may be necessary to derive a benchmark by other means. One approach is to start with the cost approved in the last rate case, which is presumed reasonable, and to escalate this for changes in relevant business conditions. The design of such escalators can be aided by price and productivity research.

An alternative approach is to compare the cost of the utility to the cost of other utilities using statistical benchmarking. This approach can generate stronger performance incentives insofar as the benchmark is fully external. However, statistical benchmarking methods that are accurate for use in ratemaking can be complex and controversial.

Another issue to consider is whether efficiency *losses* should be considered for efficiency carryover as well as efficiency *gains*. Some efficiency carryover mechanisms consider only efficiency gains while others consider efficiency losses as well. Of the latter group of examples, some consider efficiency losses only to offset gains but do not allow for *net* efficiency losses. Others allow for net efficiency losses. This issue is also germane to the extent that there is an interest in maintaining strong performance incentives in the later years of a rate plan. If an efficiency carryover mechanism carries over efficiency losses in reference years, it strengthens the incentive to contain cost in that year.

Efficiency carryover mechanisms also vary as to which years of the prior rate plan are the focus of efficiency measurement. Some look at *all* years whereas others focus only on years in which costs are relevant in determining the revenue requirements for the next rate plan.

5.5.2 How Efficiencies are Carried Over

How efficiencies are carried over depends on how revenue requirements are set in the succeeding rate plan. In many jurisdictions, revenue requirements are commonly established in the first year of a rate plan and then escalated by an external attrition relief mechanism. It can make sense, then, to treat the efficiency carryover as a supplement to the first year revenue requirement and there is no need to provide for its preservation in later years of the plan.

[43] See, for example, the plans in the state of Victoria, Australia.

However, some plans expressly guarantee companies a share of the efficiency gains achieved in any one year for a period of five years. Implementation of this requires that efficiency carryovers vary by the years of a rate plan. In year one, for example, there may be carryovers for the last five years of the proceeding plan. In year five, on the other hand, there may only be a carryover from year five of the previous plan.

Another issue in effecting an efficiency carryover is how to ensure that a carryover is really effected. Suppose, for example, that the revenue requirement in the first year of the next rate plan is equal to the cost actually incurred two years prior, with adjustments for known and measurable changes in external business conditions, plus an efficiency carryover. Carryover is then ensured. Suppose, alternatively, that the new revenue requirement is "cooked up from scratch." It may then be unclear to the company whether the new target in some fashion reflected knowledge of the low costs, achieved by hard work, in the last years of the previous plan.

5.5.3 Precedents

Experience around the world with efficiency carryover mechanisms has been less extensive than experience with some other MRP features we have discussed. Australia has been a leader, and has used these mechanisms in both power transmission and distribution regulation. The Alberta Utilities Board is using efficiency carryover mechanisms in its current MRPs for provincial energy distributors. National Grid has secured efficiency carryover mechanisms for several power distribution utilities in the Northeast US.

<u>Case Study: National Grid (Massachusetts)</u>

National Grid plc is a London-based company that owns and operates energy transmission and distribution utilities in the United States and Britain. In Britain, it owns gas and electric transmission systems and several gas distributors. In the United States it has acquired New England Electric System, Niagara Mohawk Power, Keyspan, and New England Gas.

The U.S. acquisitions sparked development of several MRPs that included creative efficiency carryover mechanisms. New England Electric System and Eastern Utilities Associates were New England electric utilities in the process of merging when they were acquired by National Grid ("Grid"). In 2000, the Massachusetts Department of Telecommunications and

Energy ("DTE") approved a settlement resolving a host of regulatory issues. The settlement detailed a "performance based" rate plan under which the Massachusetts distribution utilities of the two companies (Massachusetts Electric and Nantucket Electric) would operate.[44] The plan had a ten year term. Rates for distribution services were reduced at the outset of the plan. In the absence of a rate filing, the plan provided that the rates would remain at the reduced level for six years and then be escalated, over a 4.5 year "Rate Index Period", by a "Regional Index" of the distribution rates charged by northeast power distributors. A supplemental award penalty mechanism encouraged the maintenance of service quality.

The settlement did not require rates to be reset in a rate case at the conclusion of the Rate Index Period. However, in a section entitled "Limits on Adjusting Rates Following the Rate Plan," it limited over a ten year "Earned Savings Period" the extent to which the rates established in future rate cases can reflect the benefits of cost savings that were achieved during the plan. Specifically, let

"Earned Savings" = Distribution revenue under rates applicable in March 2009
- pro forma cost of service ("COS") (which includes applicable income taxes but not acquisition premiums or transactions costs).

Then, during the Earned Savings Period, Massachusetts Electric is permitted to add to its cost of service during any rate case the *lesser* of a) $66 million and b) 100% of Earned Savings up to $43 million and 50% of any earned savings above $43 million. Thus, if there were no earned savings there would be no revenue requirement adjustment. If there were earned savings, they would be capped at $66,000,000.

Under these terms, if National Grid filed a rate case in 2010 based on a 2009 test year and its cost of service was $30 million less than its base rate revenue in that year it would not be required to reduce rates.[45] If its COS was $80 million below base rate revenue, it would be required to reduce rates by only $14 million.

The importance of the efficiency carryover mechanism in the Massachusetts Rate Plan Settlement is suggested by the following language on page 25 of the Settlement.

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[44] See "Rate Plan Settlement," November 29, 1999. The DTE approved the settlement in D.T.E. 99-47.
[45] Massachusetts does not have forward test years.

> The full recognition and recovery of Earned Savings following the Rate Plan Period and in a defense to a complaint during the period of the Rate Plan are the central considerations and inducements for Massachusetts Electric to enter into this settlement and to commit to the long term obligations and rate reductions included in the Rate Plan.

In its order approving the Rate Plan, the DTE characterized these provisions as permitting the companies to recover the cost of the merger to the extent that any net merger savings were realized.

At the end of the plan period in 2009, a large revenue requirement increase was requested, which was rationalized in part by the need to replace aging infrastructure. The filing included a revenue decoupling plan (in conformance with evolving DTE policy) that featured a revenue cap of hybrid form. There would be expedited annual approval of future capital spending budgets in what would amount to "mini" rate cases.

National Grid did not include an allowance for earned savings in its 2009 rate request. The company may not have qualified for earned savings, but may also have considered the difficulty of asking for a revenue requirement exceeding its cost in a recession year. It may be that the earned savings formula did not properly adjust for changing business conditions, including the advancing age of the Massachusetts Electric system. The risk of such problems is especially great in a rate plan of long duration. The company had an offsetting incentive to have high cost in the historical reference year used to establish new rates. In any event, the ten year plan likely gave National Grid an opportunity to profit from its merger savings initiatives.

6. Application to Hydro-Québec

6.1 Québec Background

Special circumstances in Québec merit consideration in developing MRPs appropriate for HQ's transmission and distribution services. After considering the structure of Québec's electric utility industry, we discuss important aspects of the demand for and cost of utility services and the current regulatory system.

6.1.1 Industry Structure

Hydro-Québec is an electric power company owned by Québec's government which provides transmission, distributor, and generation services through its HQT, HQD, and Hydro-Québec Production ("HQP") divisions.

Generation

HQP is the dominant power producer in Québec. Nearly all of its power is drawn from hydrologic resources.[46] Much of the capacity is located in areas remote from major load centers.

HQP is contractually obligated to make a large block of its generation capacity available for sales to Québec power distributors at regulated prices.[47] This "Heritage Pool" takes the form of a load profile rather than a volumetric block. HQP can sell power in bulk power markets that is in excess of requests by distributors for Heritage Pool power. Sales of surplus power are made at market prices to HQD and customers in other Canadian provinces and the northeast United States. Since the generation capacity is hydro-based, sales outside the province can be timed to occur when power prices are high if export transmission capacity is available. Prices outside Québec often have summertime peaks. However, net exports have been fairly level in the last few years. In 2014, net exports accounted for about 13% of HQ's consolidated sales.[48] The great bulk of export revenue was from short term sales.[49]

Independent power producers ("IPPs") also operate in Québec. These producers chiefly generate power from wind and smaller hydro resources. The Gaspe Peninsula is an important area of recent wind power development. Most sales by IPPs have to date been made to HQD. However, some IPPs (e.g., Brookfield) have used HQT's facilities to ship power to ex provincial destinations.[50]

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[46] Hydro-Québec Sustainability Report, 2014, p.33.
[47] Article 52.2 of the Loi sur la Régie de l'Énergie.
[48] Hydro-Québec Annual Report 2014, p. 12.
[49] Hydro-Québec Form 18-K Filing with US Securities & Exchange Commission for year ended Dec. 31, 2014, p. 12.
[50] Some IPPs have requested use of HQT facilities to wheel power between Ontario and the States.

Transmission

HQT is the dominant provider of transmission services in Québec. In addition to the power from Québec's generation fleet, HQT transports large power surpluses from sparsely-populated Labrador to Québec. As a transporter of enormous power quantities over long distances, HQT is North America's largest transmission provider. HQT accounts for about 1/3 of HQ's net plant value, substantially larger than the share of HQD.[51] This is the reverse of the typical pattern in the United States, where a utility's distribution plant is typically much larger. Transmission looms especially large in the cost of serving large industrial customers.

Distribution

HQD distributes power to most Québec end users. Some end users are instead served by municipal distributors and some large-load customers receive power directly from HQT. However, all Québec end users that purchase power from a distributor receive a consolidated bill for power supply, transmission, and distributor services. HQD also operates conservation and demand management ("CDM") programs. Additional CDM programs are conducted by the Bureau de l'Efficacité et de l'Innovation Énergétiques.

6.1.2 Demand

The demand for service influences MRP design in several ways. For example, demands that are sensitive to the terms of service offered by HQT and HQD may be candidates for price caps. Unusually brisk demand growth may limit the number of utilities suitable for productivity peer groups. Growth in loads that may trigger higher capex can be limited by better rate designs and CDM programs that can be incentivized by revenue decoupling.

Distribution

Thanks in large measure to the Heritage Pool, Québec has some of the lowest residential and commercial power prices in North America. Low prices encourage many customers to use power for space heating. Given Québec's northern location, winters are severe and summers are mild. Retail demand for power is therefore winter-peaking and sensitive to winter weather. Load typically peaks in mornings and evenings on winter business

[51] Hydro-Québec Annual Report 2014, p. 81.

days. Load on distribution circuits serving chiefly residential and commercial customers can be quite peaked.

Québec has a diverse economy that includes large commercial, manufacturing, and natural resource (e.g., forestry and mining) industries. Large industrial customers accounted for a sizable 32% of HQD's sales in 2014.[52] Many large-load customers have demands that are sensitive to the price and other terms of service HQD offers. Some of these customers can shift operations into or out of Québec. Some customers self-generate using hydro power or forest product residues. Retaining the loads of customers with elastic demands and nurturing their efficient expansion is important to Québec's economy.

Residential customer growth averaged 1.1% from 2011-2014 while small business growth averaged 0.5%.[53] Distribution lines averaged 0.8% average growth during this period.[54] These trends are fairly normal by North American standards.

Average use (sales per customer) of power is important to utility finances. It trended upward for residential and commercial customers in the 2011-2014 period.[55] Residential construction has recently been brisk. Many newer homes have electric space heating whereas some homes in urban areas use oil or gas for space heating. Air conditioning loads have increased. Meanwhile, large industrial sales have been trending downward for several years.

Use of power in electric vehicles is currently small but has growth potential due to low power prices, government policy, a large urban area, and a receptive population. Electric vehicles are discouraged, however, by the vibrant, competitive market for petroleum-fueled and hybrid vehicles and the low current prices of petroleum fuels.

<u>Transmission</u>

HQT’s loads depend chiefly on demand in Québec and on the opportunities for ex provincial sales from surplus generating capacity. Demand is winter peaking. The load factor is

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[52] Hydro-Québec Form 18-K Filing with US Securities & Exchange Commission for year ended Dec. 31, 2014, p. 14.
[53] Hydro-Quebec Annual Report 2014, p. 98.
[54] *ibid.*
[55] *ibid.*, p. 99.

fairly high, however, because of the large industrial load and the strong ex provincial demand for Québec power in the summer.

Hydroelectric generating capacity averaged 1.1% annual growth between 2011 and 2014.[56] Peak load averaged 0.7% growth in that period.[57] Transmission lines averaged only 0.3% annual growth.[58] The peak load of the transmission system is expected to average 1.2% growth per annum from 2018 to 2022, spurred by expected growth in point to point services.[59]

There is a large potential for new hydro and wind projects. The incremental costs of delivering power from new large hydro projects is rising as the lower cost sites are developed. Wind generation costs are falling. Available export capacity is currently limited, and it is difficult to obtain new firm delivery service.

Demand for Québec's power outside the province is bolstered by the shuttering of coal-fired power plants, fear of increased reliance on price-volatile gas-fueled generation, and preferences for clean power supplies. Ontario is refurbishing old nuclear plants at great cost to bolster low-emission supplies. Load-following hydro from HQP can help to firm intermittent supplies from wind and solar sources. On the other hand, low gas prices have recently depressed power prices in the Northeast, and this situation may continue for some time. The potential for profitable expansion of Québec's generating capacity is thus uncertain.

Despite its dominant role in Québec transmission, demand for some services HQT offers is sensitive to its rates and other terms of service. Industrial loads of HQT's biggest customer, HQD, are sensitive to transmission prices. An alternative transmission route is under construction through the Maritime provinces to export power from Nalcor Energy's Lower Churchill project in Labrador. Rates for Québec transmission will in the future be an important determinant of how much new renewable generation in Québec is constructed to meet ex provincial demands.

[56] Hydro-Quebec Annual Report 2014, p. 99. Total capacity grew more slowly due to the closure of a nuclear plant.
[57] *ibid.*, p. 99.
[58] *ibid.*, p. 99.
[59] R-3934-2015, HQT-9, Document 1, p. 30, Tableau 11.

6.1.3 Cost

Cost conditions also influence MRP designs. For example, the appropriate mix of ARMs and cost trackers for each division can depend on their typical cost growth patterns and expected capex needs in the next few years. Indications of operating inefficiency imply the need for slower revenue growth going forward. Unusual cost conditions complicate benchmarking.

Distribution

Distribution and Customer Services With over 4 million customers scattered across a large region, HQD is one of the largest power distributors in North America.[60] HQD serves extensive rural areas as well as the large urban areas of Montreal and Québec. Operations in the cores of large urban cores and in heavily forested rural areas can both be costly. There are numerous second homes and hunting camps. Winter weather is severe. However, conditions like these are fairly common in many parts of the United States. For example, there are extensive forested areas with numerous second homes and severe winter weather in the Northeast and Upper Midwest areas of the United States. Numerous US utilities serve large urban areas. Econometric benchmarking does not require individual utilities in the sample to have all of the attributes of HQD.

A more unusual feature of HQD's system is that power supply and distributor services in some areas are provided by autonomous networks unconnected to the main provincial grid. Most of these systems are located in remote areas like the Madeleine Islands and communities north of the 53rd parallel. HQD owns 25 small-scale power generation facilities and 272 km of transmission lines to supply power to these grids.[61] Most generators burn costly diesel fuel. Autonomous networks accounted for about 8% of HQD's forecasted 2016 cost of distribution and customer services.[62] Power production assets account for about 70% of the rate base of the autonomous networks. Remarkably, the autonomous networks account for only 0.23% of forecasted 2016 retail deliveries.

[60] Hydro-Québec Annual Report 2014, p. 2.
[61] Hydro-Québec Form 18-K Filing with US Securities & Exchange Commission for year ended Dec. 31, 2014, p. 10.
[62] PEG Research calculation based on information provided in R-3933-2015, HQD-12, document 3.

HQD is engaged in an extensive buildout of advanced metering infrastructure. This program is scheduled for completion in 2016. Advanced metering infrastructure can be used to implement time-sensitive pricing.

The best available data on HQD's cost trends are probably the tables on revenue requirements ("revenus requis") ~~which they submit in their compliance filings after rate cases~~in decisions of the Régie. These tables include results for "années ~~historiques~~reels." Table 1a shows the trend in HQD's revenus requis for années ~~historiques~~ reels over the 2005-2014 period. We have added to this the company's forecasted revenue requis for 2015 and 2016 from its current rate case. It can be seen that growth in the revenus requis for Service de Distribution averaged 3.26% annually over the full 2005-2014 period for which historical data are available. Growth was much more rapid than the norm in the early years of the sample that followed expiration of the rate freeze.

Table 1b provides details of the construction of the revenus requis for Service de Distribution. It can be seen that rate base growth was particularly high from 2006 to 2008. An important issue in the design of an ARM for HQD is whether its recent historical cost growth reflected "catch up" capital spending after its rate freeze. Rate base growth is not forecasted to be especially rapid in 2015 or 2016.

HQD discusses its capex plan in its latest rate case.[63] It is noteworthy that no notable surges in capex are forecasted for the 2018-2022 period in which an attrition relief mechanism might be operative.

[63] HQD-9, document 6, *Impact Tarifaire sur Cinq Ans des Investissement Prevues. Original,* 2015-07-30.

Table 1a-Revised

Historic Revenus Requis of Hydro-Québec Distribution[fn]

Annee	**Achats d'Électricité**		**Service de Transport**		**Service de Distribution**		**Revenu Requi Total**	
Year	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate		Growth Rate
	[A]		[B]		[C]		[A+B+C]	
2004	4,567		2,313		2,270		9,150	
2005	4,706	2.99%	2,313	0.00%	2,370	4.34%	9,389	2.58%
2006	5,040	6.88%	2,313	0.00%	2,505	5.53%	9,859	4.88%
2007	4,986	-1.09%	2,553	9.87%	2,727	8.47%	10,265	4.04%
2008	4,976	-0.20%	2,727	6.60%	2,859	4.74%	10,562	2.85%
2009	4,616	-7.50%	2,677	-1.85%	3,032	5.88%	10,325	-2.26%
2010	4,729	2.41%	2,633	-1.68%	3,187	4.97%	10,548	2.13%
2011	4,967	4.92%	2,660	1.03%	3,052	-4.30%	10,679	1.24%
2012	4,896	-1.44%	2,584	-2.90%	3,061	0.28%	10,541	-1.31%
2013	5,331	8.51%	2,607	0.89%	3,109	1.56%	11,047	4.69%
2014	5,617	5.23%	2,739	4.95%	3,144	1.13%	11,501	4.03%
2015	*6,118*	*8.54%*	*2,784*	*1.62%*	*3,018*	*-4.09%*	*11,920*	*3.58%*
2016	*6,356*	*3.82%*	*2,784*	*-0.01%*	*2,830*	*-6.43%*	*11,970*	*0.42%*
Averages								
2005-2014		**2.07%**		**1.69%**		**3.26%**		**2.29%**
2011-2014		**4.30%**		**0.99%**		**-0.33%**		**2.16%**

[fn] All amounts listed here are in millions of dollars.

Source: For years 2004-2013, data are for "années reels ~~historiques~~" as reported in the Regie's rate case decisions. Data for 2014 (année historique), 2015 (année de base), and HQD's proposed 2016 test year are from HQD's pending rate case filing.

Note: Italicized values are forecasts, not historical values.

Table 1b

Historic Components of the Revenus Requis of HQD's Distributor Services[1]

Annee	Base de Tarification		Amortissement et déclassement		Dépenses[2]		Dépenses Totales[3]		Service de Distribution Total	
Year	Level	Growth Rate	Level [A]	Growth Rate	Level [B]	Growth Rate	Level [A+B]	Growth Rate	Level	Growth Rate
2004	8,319		447		1,202		1,649		2,270	
2005	8,447	1.53%	489	9.00%	1,246	3.64%	1,735	5.13%	2,370	4.34%
2006	8,875	4.94%	570	15.29%	1,306	4.69%	1,876	7.80%	2,505	5.53%
2007	9,413	5.89%	591	3.64%	1,364	4.32%	1,955	4.11%	2,727	8.47%
2008	9,861	4.65%	640	8.04%	1,408	3.20%	2,049	4.69%	2,859	4.74%
2009	9,741	-1.22%	853	28.61%	1,374	-2.47%	2,227	8.32%	3,032	5.88%
2010	9,990	2.52%	833	-2.36%	1,440	4.72%	2,273	2.07%	3,187	4.97%
2011	10,306	3.11%	802	-3.71%	1,407	-2.35%	2,209	-2.85%	3,052	-4.30%
2012	9,896	-4.06%	885	9.79%	1,403	-0.30%	2,288	3.48%	3,061	0.28%
2013	10,139	2.43%	773	-13.51%	1,471	4.78%	2,244	-1.90%	3,109	1.56%
2014	10,551	3.98%	817	5.58%	1,467	-0.29%	2,285	1.77%	3,144	1.13%
2015	*10,529*	*-0.20%*	*696*	*-16.12%*	*1,548*	*5.39%*	*2,244*	*-1.78%*	*3,018*	*-4.09%*
2016	*10,683*	*1.45%*	*633*	*-9.40%*	*1,445*	*-6.88%*	*2,079*	*-7.66%*	*2,830*	*-6.43%*
Averages										
2005-2014		**2.38%**		**6.04%**		**1.99%**		**3.26%**		**3.26%**
2011-2014		**1.37%**		**-0.46%**		**0.46%**		**0.13%**		**-0.33%**

[1] All amounts listed here are in millions of dollars.

[2] Dépenses are defined as the revenue requirement for distribution services less "amortissement et déclassement" and the "rendement sur la base de tarification". They include "Charges d'exploitation", "achats de combustible", and taxes.

[3] Dépenses totales are equal to the revenue requirement for distributor services less the "rendement sur la base de tarification".

Source: For years 2004-2013, data are from the columns labeled "réel" or "année historique" of the Base de Tarification and Revenus Requis tables included in the Regie's rate case decisions. Data for 2014 (année historique), 2015 (année de base), and HQD's proposed 2016 test year are from HQD's pending rate case filing.

Note: Italicized values are forecasts, not historical values.

Power Supply To supply customers with power, HQD supplements Heritage Pool supplies with power from other sources. Supplemental power is procured via calls for tenders. Calls have been limited by policymakers to certain kinds of resources and/or communities. HQD's electricity supply plans are approved by the Régie.

Procurement of supplemental power supplies has substantially raised the price of power for HQD customers. One reason is that the price of contracted post patrimonial supplies substantially exceeds that of Heritage Pool power. Another is that HQD is required by law to take supplies from IPPs first. A portion of available Heritage Pool supplies is therefore sometimes not utilized, and HQP rather than HQD holds the right to sell surplus Heritage Pool power on the open market.

Transmission

The operating conditions of HQT are unusual. A large portion of the power carried is accessed at remote locations on the Canadian Shield. Extra high voltage (e.g., 735 kV) lines are used to ship power from many remote locations. Operations on the Shield are generally challenging due to limited soil cover, extensive forestation, severe winter weather, and a lack of roads. These special operating conditions complicate but do not prohibit good benchmarking.

Construction of most transmission projects is competitively bid. High construction standards can raise cost. HQT has recently adopted an "Asset Management model" that calls for better integration of its maintenance and sustainment strategies. A touted advantage is improved reliability.

Table 1c shows the trend in revenus requis of HQT for the années ~~historiques~~ reels~~from their compliance filings after rate cases~~, together with forecasts of the revenue requis for 2015 and 2016 from their current rate case. Over the full 2002-2014 period for which historical data are available the total revenu requi averaged 1.65% growth. Rate base growth is forecasted to be brisk in 2015 and 2016. There is some evidence of a stairstep pattern in which years of high rate base growth are followed by years of slow growth.

The capex plan of HQT is discussed in the current rate case.[64] Plant additions can be seen to be fairly variable. They will be especially high in 2018 and 2019 but much lower on average in the remaining years in which an ARM might apply.

Operating Performance

Public ownership of a utility typically does not encourage operating efficiency because senior managers do not answer to shareholders vigilant about bottom line results. Hydro-Québec's workers are unionized. Our analysis in Section 2 suggests that frequent rate cases for the T&D divisions have weakened their performance incentives.

On the other hand, Québec's government relies on HQ for revenue and HQ distributes a high proportion of its net income as dividends.[65] During the 2013-2014 rate case, the government issued a decree in December 2012 requiring the Régie to ~~fix the operating expenses of HQT and HQD at the levels of the last rate case so that efficiency gains asked of HQD (e.g.,~~

[64] HQT-9, Document 1, R-3934-2015, *Planification du reseau de transport*, 2015-07-29.
[65] Hydro-Québec Form 18-K Filing with US Securities & Exchange Commission for year ended Dec. 31, 2014, p. 21.

~~reduction of employees) could be kept by the government~~be mindful of its need for revenue in setting rates for HQ.

Table 1c-Revised

Historic Revenus Requis of Hydro-Québec TransÉnergie[1]

Annee	Base de Tarification		Amortissement et déclassement		Dépenses[2]		Dépenses Totales[3]		Revenu Requi Total	
Year	Level	Growth Rate	Level [A]	Growth Rate	Level [B]	Growth Rate	Level [A+B]	Growth Rate	Level	Growth Rate
2001	14,192		438		771		1,208		2,586	
2002	14,109	-0.58%	469	6.86%	768	-0.27%	1,237	2.37%	2,606	0.76%
2003	14,039	-0.50%	484	3.23%	807	4.95%	1,292	4.30%	2,473	-5.23%
2004										
2005	14,571		493		889		1,382		2,600	
2006	14,799	1.55%	534	7.98%	917	3.12%	1,451	4.89%	2,611	0.40%
2007	14,983	1.23%	569	6.29%	949	3.40%	1,518	4.47%	2,675	2.45%
2008	15,674	4.51%	652	13.61%	795	-17.64%	1,447	-4.75%	2,733	2.12%
2009	16,046	2.35%	781	18.06%	775	-2.59%	1,556	7.25%	2,824	3.29%
2010	16,666	3.79%	950	19.54%	748	-3.56%	1,698	8.70%	2,999	6.01%
2011	16,875	1.24%	962	1.30%	774	3.43%	1,736	2.24%	3,009	0.35%
2012	16,894	0.12%	995	3.33%	711	-8.43%	1,706	-1.74%	2,992	-0.60%
2013	17,117	1.31%	965	-3.09%	786	10.02%	1,751	2.59%	2,934	-1.94%
2014	17,591	2.73%	1,033	6.83%	810	2.98%	1,843	5.12%	3,139	6.75%
2015	*18,691*	*6.06%*	*967*	*-6.53%*	*933*	*14.14%*	*1,901*	*3.08%*	*3,203*	*2.04%*
2016	*19,417*	*3.81%*	*1,035*	*6.75%*	*766*	*-19.75%*	*1,801*	*-5.38%*	*3,150*	*-1.69%*
Averages										
2002-2014		**1.65%**		**6.60%**		**0.39%**		**3.25%**		**1.49%**
2011-2014		**1.35%**		**2.09%**		**2.00%**		**2.05%**		**1.14%**

[1] All amounts listed here are in millions of dollars.

[2] Dépenses include all expenses except for "amortissement et déclassement" in HQT's revenue requirement.

[3] Dépenses totales is the equivalent to "Dépenses Nécessaires à la Prestation du Service" in HQT's revenue requirement. This is the entire revenue requirement less the "rendement sur la base de tarification".

Source: For years 2001-2013, data are for "années reels ~~historiques~~" as reported in HQT's compliance filings to the Regie's rate case decisions. Data for 2014 (année historique), 2015 (année de base), and HQT's proposal for 2016 are from HQT's current rate case filing.

Note: Italicized values are forecasts, not historical values.

Here are some indicators that shed light on the recent operating performances of the two divisions.

- The overall number of HQ's employees has declined in recent years due to improved efficiency, fewer meter readers and nuclear workers, and not replacing workers when they retire.[66]

[66] The number of HQ employees has dropped by an average rate of 3.5% during the 2011-2014 period. Hydro-Québec Annual Report 2014, p. 99.

- Capacity utilization is improving as transmission system use approaches capacity. This improves cost/MW metrics.
- HQ annually benchmarks its prices in Montreal to those in other North American cities. While HQ tends to have the lowest prices, it's difficult to know if T&D accounts for any of this advantage given the low cost of Heritage Pool power.

6.1.4 Regulation

The current regulatory system has a major bearing on an MRP proposal. The system may engender problems, such as weak performance incentives, that can be reduced with regulatory reforms. Some features of current regulation may be worth keeping because they work well or do not work badly enough to merit change. Rate designs may or may not need adjustments to encourage customers to use the system in less costly ways. Indications of chronic overearning under current regulation may presage regulatory capture under incentive regulation. Existing marketing flexibility provisions shed light on the need for marketing flexibility in an MRP.

<u>Jurisdiction</u>

Rates charged by HQD and HQT are regulated by the Régie subject to provisions of the Act Respecting the Régie de l'Energie. Regulation began for HQT in 1997 and for HQD after a restructuring in 2000.[67] HQD did not receive a rate adjustment until 2004 following a rate freeze.

<u>Rate Cases</u>

Both companies have filed rate cases in most years since 2004. Rate cases have forward test years. The Régie allows new assets to be included in rate base if they are expected to be in service during the future test year.

Returns on construction work in progress are not permitted in rates, but the Régie does permit an allowance for funds used during construction when assets become used and useful. This magnifies the revenu requi impact when larger plant additions become used and useful.

[67] However, the Régie did not become active in ratesetting until 2002.

All power producers make up front payments for costs of connecting transmission facilities that exceed a rate neutrality budget. Especially remote producers may pay substantial upfront costs.[68] These contributions are not added to rate base. Roughly half the cost of the La Romaine system extension was paid for this way. Thus, rate cases for HQT chiefly address the cost of the core transmission system.

Since 2008, substantial overearning has occurred frequently for both HQT and HQD. Overearning has exceeded a billion dollars over these years. Intervenors maintain that understatement of load growth and overstatement of cost growth have been major contributing causes.

Intervenors complain that information asymmetry has been a noteworthy problem in rate cases. They state that HQ's responses to information requests are often incomplete, immaterial, or lack substance.

HQ has changed accounting standards since 2005. This may complicate accurate measurement of the divisions' productivity trends. This and other issues affecting the potential for benchmarking and productivity studies should be explored through data requests in later stages of the proceeding so that the Régie has a better basis for deciding the scope of any Phase II study.

<u>Cost Trackers</u>

HQD currently recovers a large share of its cost via trackers. There is a "compte de pass-on" for power purchase expenses. In addition, there are a number of variance accounts ("compte d'ecarts) that include those for HQT's transmission services, pensions, major outages, the Bureau of Energy Efficiency and Innovation, and unforeseen events in autonomous networks. HQT has fewer cost trackers than HQD. There is a variance account for retirement costs.

[68] The same policy applies to customers. The *politique d'ajou* is under review in R-3888-2014.

Earnings Sharing

An earnings sharing mechanism was approved by the Régie in 2014 but suspended by the provincial legislature. The government evidently wished to secure the benefits of higher earnings.

Planning

A public planning process is not well developed for HQ's transmission or distribution. Capex plans are discussed in rate cases. Intervenors complain that they are often not provided with enough information to effectively participate and engage in planning processes. Effective oversight of T&D capex was noted in Section 5.1.2 to be challenging. Substantial resources are needed to properly develop independent views.

The Régie is required to authorize acquisition or construction of transmission assets with a value of $25 million and of distribution assets with a value of $10 million.[69] The range of alternatives to the proposed capex that are considered in these hearings is limited to those advanced by the proponent. By virtue of these hearings, numerous capex programs have already been approved that would take place during the MRP periods.

Rate Designs

The price for Heritage Pool power was fixed by the provincial government at 2.79 cents/kWh in 2000.[70] Since 2014, this price has been permitted by law to escalate by growth in a consumer price index for all retail service classes save that for large-load customers (Rate L).

HQT provides transmission and ancillary services under a non-discriminatory Open Access Transmission Tariff ("OATT") that meets the reciprocity condition of US regulation. HQD uses HQT's "postage stamp" native-load transmission service. Point to point services are used by IPPs and HQP for their ex provincial sales. In 2014, the Régie authorized HQT to receive $2.8 billion in revenue from native load transmission and 374 million from point to point services.[71]

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[69] Article 73 of the Loi sur la Régie de L'Energie.
[70] Quebec National Assembly, 36th legislature, 1st session, Bill 116, An Act to amend the Act respecting the Régie de l'énergie and other legislative provisions, as enacted June 16, 2000.
[71] Hydro-Québec Form 18-K Filing with US Securities & Exchange Commission for year ended Dec. 31, 2014, p. 32.

Firm and non-firm point to point services are available. Firm services are offered on a short term (less than once year) and a long term (one year or more) basis. Long term firm point to point service is available on a first-come, first-served basis, and available service has been subscribed by HQP. Point to point customers can resell their rights to other eligible customers subject to a price cap.[72]

HQD pays a monthly demand charge for native-load transmission service equal to 1/12 of HQT's annual revenue requirement less the revenues expected from point to point services. Revenue from point to point customers is later trued up to actuals. These terms of service effectively guarantee HQT the recovery of its revenue requirement.

HQD has a rate design for most residential customers that features a relatively low customer charge for a Canadian utility of about $12/month.[73] This charge has not changed for many years, and thus has fallen in real terms. HQD has indicated in its current rate case that it is considering minimum bills for residential customers.[74] This would permit high usage charges while still providing some revenue stability.

Performance Metrics

HQT and HQD provide data on performance metrics in rate cases. Both divisions report metrics addressing their reliability, customer satisfaction, and cost. The cost metrics are typically simple unit cost ratios (e.g. distribution cost per customer). In addition, HQD reports some customer service metrics, while HQT's reports an extensive list of environmental metrics. There are currently no rewards or penalties associated with any of these metrics. Listings of some of these metrics that have been filed in the pending rate cases are provided in Tables 2a and 2b.

HQD's reliability performance using these metrics has been fairly stable. However, systemwide averages may mask performance declines at the local level. Several stakeholders have concerns about the definitions of some performance metrics. They also have concerns

[72] See Section 23 of HQT's Open Access Transmission Tariff
[73] Hydro-Québec Electricity Rates Effective April 2015, p. 12.
[74] R-3933-2015, HQD 14, Document 2, p. 16, lines 23-24

that in terms of reliability and customer service the metrics are not sufficiently granular to ensure that certain pockets of customers do not receive unacceptably poor service.

Table 2a

Metrics Reported by Hydro-Québec TransÉnergie in Its Pending Rate Case[1]

Metric
Satisfaction de la clientèle
Partenariat qualité avec les clients point à point
Partenariat qualité avec le Distributeur
Fiabilité du service
Nombre de pannes et interruptions planifiées
Durée moyenne des pannes et interruptions planifiées
Indice de continuité-Transport
Indice de continuité-Opérationnel
Défaillances d'équipement
Incidents
Travaux programmés
Indice de continuité-Autres
Facteurs climatiques
Faune & environnement
Autres
Responsabilité sociale
Fréquence des accidents de travail

Metric
Evolution du coût des charges nettes d'exploitation
Coûts directs d'exploitation et de maintenance par km de circuit
Charges nettes d'exploitation en fonction de l'énergie transitée
Charges nettes d'exploitation en fonction de la capacité du réseau de transport
Evolution du coût de service
Coût de service total, excluant les taxes, en fonction de l'energie transitée
Coût de service total, excluant les taxes en fonction de la capacité du réseau de transport
Evolution du coût des immobilisations
Coût des immobilisations nettes en fonction de l'énergie transitée
Coût des immobilisations nettes en fonction de la capacité du réseau de transport
Evolution du coût total par rapport à la valeur totale de l'actif
Lignes coût total / valeur totale des actifs

Table 2a (continued)

Metrics Reported by Hydro-Québec TransÉnergie in Its Pending Rate Case

Metric
Indicateurs environnementaux *Maîtrise intégrée de la vegetaton dans les emprises de lignes*
Superficie totale des emprises a entretenir
Superficie traitée mécaniquement
Superficie traitée à l'aide de phytocides
Superficie traitée mécaniquement et sélectivement a l'aide de phytocides
Gestion des matières résiduelles ("MR") et des huiles isolantes minérales ("HIM")
Taux de réutilisation des huiles isolantes minérales
Gestion des déversements accidentels dans l'environnement
Déversements accidentels
Déversements accidentels de moins de 100 litres
Déversements accidentels entre 100 litres et 4000 litres
Déversements accidentels de plus de 4000 litres
Taux de récupération des déversements
Metric
2014 Corporate Objectives **Clients**
Indice de continuité - Transport (excluant les événements exceptionnels selon la norme 1366-2012 de l'Institute of Electrical and Electronics Engineers)
Conformité aux normes de fiabilité NERC/NPCC (excluant les non-conformités déclarées)
Autorisation des projets d'investissement de la demande d'investissement 2014 pour les projets de moins de 25 M$
Demandes d'investissement supérieurs a 25 M$ déposées à la Régie de l'énergie en 2014
Employees
Taux de fréquence des accidents avec perte de temps et assistance médicale (par 200 000 heures travaillées)
Shareholder
Bénéfice net réglementaire non consolidé excluant la variation des normes comptables, taxes, frais financiers, frais corporatifs
Réalisation des mises en service de projets

Source: R-3934-2015, HQT-3, Document 1 and HQT-3, Document 2

[1] This is not a complete list. There are a handful of metrics for which it has been difficult to get documentation.

Table 2b

Metrics Reported by Hydro-Québec Distribution in Its Currently Pending Rate Case

SATISFACTION DE LA CLIENTÉLE
Indices de satisfaction
Clients **résidentiels**
Clients **Grands comptes et Affaires-autres**
Clients **Grande puissance**
FIABILITÉ DU SERVICE
Indice de continuité - Distribution
Indice de continuité **brut (minutes)**
Indice de continuité **normalisé (minutes)**
ALIMENTATION ÉLECTRIQUE
Demandes d'alimentation
Délai moyen de raccordement simple en aérien (jours)
Délai moyen de prolongement réseau aérien / Délai attente client (jours)
Délai moyen de prolongement réseau souterrain / Délai attente client (jours)
Interruptions planifiées
Taux de respect global des **interruptions planifiées**
Reléve de compteurs
Taux de **reléve** de compteurs
SERVICES A LA CLIENTÉLE
Délai moyen de réponse téléphonique (secondes)
Clients **résidentiels**
Clients **commerciaux**
Taux d'abandon téléphonique
Clients **résidentiels**
Clients **commerciaux**
Appels des clients
Nombre d'appels par client
Taux de résolution au 1er appel
Clients **résidentiels**
Clients **commerciaux**
Courriels des clients
Nombre de courriels par client
Contacts Web
Nombre de contacts Web par client

Table 2b (continued)

Metrics Reported by Hydro-Québec Distribution in Its Currently Pending Rate Case

SÉCURITÉ
Sécurité du public
Décés provoques par **électrocution** dans la population
Sécurité des employés
Taux de fréquence des accidents
INDICATEURS D'EFFICIENCE PRIVILÉGIÉS PAR LE DISTRIBUTEUR
Indicateurs globaux du Distributeur
Coût total Distribution et services a la clientele ($) par abonnement
Coût total Distribution et services a la clientele (¢) par kWh normalisé
Charges d'exploitation nettes Distribution et services a la clientele ($) par abonnement
Immobilisations en exploitation nettes ($) par abonnement
Indicateurs processus services a la clientele
Coût total services a la clientele ($) par abonnement
Charges d'exploitation nettes services a la clientele ($) par abonnement
Indicateurs processus Distribution
Coût total Distribution ($) par abonnement
Charges d'exploitation nettes Distribution ($) par abonnement

Source: R-3933-2015, HQD-2, document 1

A separate set of reliability rules called reliability standards has been established for transmission and the bulk power system. A division of HQT, the Direction – Contrôle des mouvements d'énergie ("HQCME"), is the province's reliability coordinator, balancing authority, and interchange authority. HQCME proposes standards for approval by the Régie which are essentially based on those adopted by North American Electric Reliability Corporation ("NERC") or Northeast Power Coordinating Council ("NPCC").

About a dozen Régie-approved reliability standards are in effect today with more than a dozen additional standards going into effect at the start of 2016. Numerous additional standards have been proposed for inclusion, with still more standards set to be proposed in the short term. The currently effective standards address real power balancing control, disturbance control performance, inadvertent interchange, emergency operations planning, coordination of real-time activities between reliability coordinators, transmission operations, reporting system operating limit and interconnection reliability operating limit violations, and responses to transmission limit violations. While some of these standards, like those for real power balancing control performance and disturbance control performance, have clear metrics, many do not.

Enforcement of the bulk market reliability regime is described in the *Québec Reliability Standards Compliance Monitoring and Enforcement Program* ("QCMEP") and relies on agreements with the NERC and the NPCC. The QCMEP outlines the entire compliance monitoring process including audits, self-certification, spot checks, and investigations of reliability violations. If any violations are suspected to have occurred, the NPCC will usually serve as the lead investigator, developing a report for the Régie on whether a violation occurred and its recommendations on whether or not to impose sanctions on the company. If a violation is found, the NPCC will send a notice of non-compliance. HQT may then enter confidential settlement discussions with NPCC and if successful, the NPCC sends the settlement to the Régie for approval. If no settlement is reached, the Régie makes the final determination whether a violation occurred and what type of punishment, if any, is appropriate. A simplified investigation procedure is available for less serious reliability violations that allows the investigated entity to come into compliance with the reliability standard without being fined or sanctioned.

Marketing Flexibility

There is some flexibility in the rates and services offered to retail customers of Hydro-Québec. Rates in some special contracts include a risk sharing arrangement whereby the price is indexed to currency exchange rates or commodities. The variance from standard rates is sometimes absorbed by HQP. A number of special contracts (currently around 8) have been approved by the Government. The Régie recently approved a new electricity rate for business customers of HQD designed to promote economic development. A separate load retention rate is also available for customers that are experiencing financial distress and have received discounts from their other vendors. Revenue losses from this program would be absorbed by other industrial customers.

Conservation and Demand Management

HQD has had a sizable CDM program called the Plan Global en Efficacité Énergétique ("PGEE") for 10 years. There are programs for most customer groups. The PGEE focuses chiefly on conservation programs. Funds for the Bureau de l'Efficacité et de l'Innovation Énergétiques are also gathered in HQD's rates.

Energy efficiency targets are set by the government. A new provincial energy policy that may address CDM is under development. The Régie has no authority to expand CDM programs.

Opportunities for cost effective CDM are limited, for several reasons. One is the generally low retail prices of power in Québec. Another is HQD's take or pay contracts with independent power producers, which has meant in recent years that low cost Heritage Pool power is often at the margin. The efficiency gains that are easiest to achieve have mostly been addressed by previous plans.

Load peakedness is a mounting problem due to its implications for transmission and distribution capex and the increasing mismatch between the retail load profile and the Heritage Pool load profile. HQD will likely need more peak supply capacity in the next few years if present trends continue. The capacity of HQT is increasingly strained.

This situation argues for greater focus on peak load reductions. HQD has shown increasing receptiveness to demand management initiatives. There is a new pilot project for remote-controlled water heaters. Bill credits for load reductions in peak hours have been discussed.

The newly installed smart meters could play an important role in containing peak load growth via mandatory or optional time sensitive rates. This potential use of the meters was not emphasized by HQD when they sought approval for the capex. Gas distribution customers in Québec face a separate charge for load balancing that exposes them to the cost of load peakedness.

LRAMs, revenue decoupling, and PIMs for conservation and demand management have not previously been advocated in HQD rate cases. The revenue of HQD is weather normalized, however. This reduces the risk of experimental rate designs with high usage charges. There is a flow through of CDM program cost that is amortized, providing some positive return on CDM. There is precedent for CDM performance incentive mechanisms in Québec's gas distribution industry.

6.1.5 Conclusions

Our discussions of MRPs in Sections 3-5 and of the operating environment of the divisions in Section 6.1 prompts the following conclusions.

1. Due to reliance on power supplies from remote generating sites in Québec and the low price of Heritage Pool power, transmission services account for an unusually large share of the power bills of most Québec customers. The cost of transmission looms especially large in the bills of large industrial customers. Encouraging HQT to meet regulated quality standards at low cost should thus be an important goal of Québec regulation. Containment of capex is the key to low transmission cost.

2. HQD and HQT operate under a system of frequent rate cases that involves weak cost containment incentives, chronic overearning, and unnecessarily high regulatory cost.[75] There is a strong incentive for each division to grow its rate base. This is a serious concern in capital-intensive businesses like power T&D.

   HQD has an especially weak incentive to contain the cost of power supply and transmission services that it purchases. There is, for example, little incentive for HQD to resist government intervention in the choice of supplemental power supplies. All in all, there is a material risk that the rates customers pay will be well above efficient levels, needlessly offsetting some of the advantage of low cost generation in Québec.

3. CDM is a useful tool for managing HQD's power supply, transmission, and distributor costs. Peak load management is especially useful since all three of these costs are sensitive to peak demand. HQD lacks strong incentives to embrace all cost-effective CDM today. Frequent rate cases and forward test years do reduce this division’s lost revenue disincentive, and CDM expenses are flowed through and amortized. Factors discouraging embrace of efficient

[75] One cost *advantage* of the current system is that the Régie does not have to regulate multiple utilities.

CDM include the strong incentive to grow rate base which frequent rate cases provide and the flowthrough of power supply and transmission costs. Usage charges are fairly high, and HQD has no revenue decoupling or LRAM. Amortization of CDM expenses does little to encourage time sensitive pricing or miscellaneous market transformation initiatives that don't involve large expenses.

4. Stakeholders are concerned that Hydro-Québec's breakdown into separate generation, transmission, and distribution divisions does not ensure their independent operation. It is theoretically difficult for managers in one division not to be mindful of the financial impact of their decisions on other divisions. For example, CDM programs of HQD can potentially reduce the opportunity for HQT to grow its rate base, but might boost the earnings of HQP by freeing up more Heritage Pool power for sale at market prices. HQD has little incentive to lobby the government to permit it rather than HQP to make off system sales from surplus heritage pool supplies so that it can pass on the margins to retail customers. Lax management by HQD of its supplemental power purchases from HQP does not affect the earnings of the former but can boost the earnings of the latter. HQT potentially has an incentive to provide better quality point to point services to HQP than it does to IPPs. HQT may consider the interests of HQP when allocating cost between native load and point to point services.

6.2 Recommendations

6.2.1 Introduction

Multiyear rate plans can strengthen the performance incentives of Hydro-Québec. There can be stronger incentives to use CDM, new technologies, and other tools to slow rate base growth. Superior returns can be achieved for superior performance. Although the small number of utilities in Québec reduces the regulatory burden, MRPs can nonetheless streamline regulation, freeing up resources to address other key issues like capex and power supply planning, reliability standards, and the allocation of HQT's revenue requirement between native load and point to point services.

MRPs are already used in Québec to regulate Gazifère, and the Régie has ordered their use in Gaz Métro's future regulation. The government-imposed cap on the price of Heritage

Pool power is tantamount to an MRP for Hydro-Québec Production which has no fixed plan term.[76]

Despite their potential advantages, MRPs must be carefully designed if they are to produce material net benefits and share them fairly between Hydro-Québec and its customers. The Régie has some experience with the forward-looking ratemaking that MRPs entail because of its routine use of forward test years and reviews of large plant additions. There is nonetheless a risk of disappointing outcomes and the capture of MRP regulation by Hydro-Québec. The Alberta Utility Commission has already launched a process for improving its MRPs just a few years after their province-wide roll-out.

A transition to MRPs may require a change in culture of Hydro-Québec and other participants in Québec regulation. There is no practical way for MRPs to simultaneously strengthen performance incentives materially and ensure that rates of return are always close to allowed levels. A culture of cost recovery entitlement is less suited to operation under MRPs than an attitude, more typical of Québec businesses, that a competitive rate of return is, with sound management and a little luck, attainable in the long run.

HQD and HQT need separate MRPs due to differences in a number of key business conditions which we have explained in previous sections. Salient areas of difference include the following.

- Historical and forecasted cost trajectories
- Cost drivers that are relevant in the design of the scale escalator of an index-based ARM
- Input price trends (e.g., capital price is more important for transmission)
- Base productivity trends in transmission and distribution
- Appropriate service quality metrics
- Costs that need tracking
- Role of utility in CDM

[76] MRPs that cap prices for utility services in non-competitive markets but decontrol prices for services to competitive markets have been approved in various utility industries over the years.

Good MRPs are encouraged when sensible goals are established at the outset. The following goals are salient, and are in line with Section 48.1 and other provisions of Québec law.

- Strong, balanced incentives to provide quality service cost effectively, with mindfulness of environmental impacts.
- Streamlined regulation
- Fair opportunity for a well-managed utility to earn its target rate of return
- Benefits of performance gains shared fairly between utilities and their customers.
- Utilities can earn superior returns for superior performance.

The following checklist enumerates the most important issues that must be addressed in the design of MRPs for HQD and HQT.

	HQD	HQT
Relaxing the Revenue/Usage Link	x	x
Attrition Relief Mechanism	x	x
Cost Trackers	x	x
Incentive Compatible Menus	x	x
Performance Metric System	x	x
Earnings Sharing Mechanism and Off Ramps	x	x
Marketing Flexibility	x	x
Plan Termination Provisions	x	x
Regulation of Autonomous Systems	x	
Procedure for Plan Development and Approval	x	x

We discuss each issue in turn.

6.2.2 Relaxing the Revenue Usage Link

A threshold issue in plan design is whether and how to relax the link between base rate revenue and system use. Answers may differ for transmission and distribution.

<u>Distribution</u>

For HQD, we believe there is a strong case for revenue decoupling for residential and small business customers. Controversy would diminish over billing determinant forecasts since earnings would ultimately be unaffected by chosen forecasts. Chronic overearning from downward-biased forecasts of load growth could not occur. Lower risk of demand fluctuations would be welcomed as HQD adjusts to rates that track its cost less closely.

The lost revenue disincentive for HQD to undertake various initiatives to foster CDM would be eliminated. For example, HQD would not suffer lost revenue between rate cases if it instituted time-sensitive rates or ramped up demand response programs. It is important to note that the lost revenue disincentive would be much greater under an MRP with price caps than it is under the current regime of frequent rate cases.

Price caps may make sense for those HQD services for which the Régie wishes to encourage an expansion of efficient use. Services that merit encouragement include those for electric vehicles and large load customers.[77] An LRAM can be established to compensate HQD for base rate revenue lost due to CDM programs for large load customers.

If decoupling is instituted, several issues in the design of the revenue decoupling mechanism will require resolution. One is whether decoupling should apply to industrial customers. If the answer is "yes", an important further issue is whether baskets should be implemented that insulate residential and commercial customers and industrial customers from the revenue impact of fluctuations in each other's revenue.

To further encourage HQD to embrace cost effective CDM we recommend two additional provisions. CDM costs should continue to be amortized and should be subject to Y factor treatment. One or more performance incentive mechanisms should be developed to strengthen the incentive to reduce peak loads. HQD could, for example, be rewarded for its documented success in slowing peak load growth.

Transmission

HQT's revenue is already insensitive to system use under its OATT. A revenue cap ARM can be developed to establish a revenue requirement for these rates using any of the ARM design approaches discussed in Section 4.

The price cap option for HQT nonetheless merits some consideration. Under this option, the OATT would require revision so that HQD's bill is a function of its forecasted or actual peak demand and is not the residual portion of HQT's revenue requirement not paid for

[77] Price cap treatment of EV rates does not necessarily entail HQD's ownership of additional public charging stations. These stations may, to the contrary, be owned and operated by third party providers and commercial end users. HQD will have more incentive to encourage other parties to own these stations if the cost of building more charging stations isn't tracked.

by point to point customers. Here are some arguments favoring eventual implementation of the price cap approach for HQT.

- Peak load containment could reduce HQD's transmission bill between rate cases whether or not HQT contains its peak load capacity.
- The cost HQD's customers incur for HQT's services would be less sensitive to the level of point to point services between rate cases.
- HQT would have stronger incentives to boost system utilization. It would, for example, have a greater vested interest in retaining large industrial loads and in fostering additional exports. Discounts could in principle be advanced by HQT to HQD to retain or foster industrial loads.

Here are some arguments against price caps for HQT.

- Price caps could increase HQT's revenue volatility and operating risk if rates were based on actual demand. This risk could, however, be reduced by a weather normalization mechanism.
- Increased use of point to point services can accelerate system expansions, and HQD may shoulder an unfair share of the cost.
- Price caps could be used to encourage discounts. However, the principle user of point to point services, where demand elasticity is greatest, is HQP. Furthermore, HQT already offers several point to point service options. Discounts have traditionally come from HQP.
- A change in the OATT would require extensive review by the Régie.

We conclude from this analysis that price caps don't make sense for HQT in a first generation MRP.

6.2.3 ARM Design

The ARM was shown in Section 4 to be a critically important issue in MRP design. ARMs for HQT and HQD would likely compensate the divisions for cost growth over a period that starts in 2018 and ends in 2021 or 2022. Numerous approaches to ARM design are well established. The approach that makes the most sense may differ between transmission and distribution.

<u>General Comments</u>

The all-forecast approach to ARM design has been used in several jurisdictions and been found to have significant problems. Total cost forecasts involve more complexity and controversy. It can be difficult to ascertain the value to customers in a given forecast. Although the Régie has some experience with forward test years and capex forecasts, it may not be willing to incur the startup costs needed to develop solid independent views of future revenue requirements. Alternative approaches to ARM design like indexing and hybrids reduce the role of cost forecasts.

If the Régie instead prefers the all-forecast approach, extensive use should be made of statistical benchmarking and productivity research to reduce regulatory cost and ensure value for customers, as in Australia and Ontario. For example, sensible productivity-based formulas for forecasting O&M expense revenue could be required. Portions of the capex forecast can be based on test year capex or historical norms with an adjustment for inflation.

Distribution

We recommend an index-based ARM design for HQD. As we explained in Section 4, this approach has been used by many commissions to regulate gas and electric power distributors, due in part to their typically gradual and predictable cost growth. The Régie already uses this approach to regulate Gazifère, and has mandated its use in Gaz Métro’s upcoming MRP.

HQD’s capex forecast for the years after 2017 does not suggest ~~an expectation~~an insurmountable problem with ~~of~~ cost surges. There is good control for inflation risk under the index-based approach. HQD customers would be ensured the benefit of industry productivity growth and HQD would face the challenge of operating under an external productivity growth standard.

A candidate revenue cap for HQD would have the general form

$$\textit{growth Revenue}^{HQD} = \textit{Inflation} - X + \textit{growth Customers}^{HQD} + Y + Z$$

$$X = \textit{Base Productivity Trend}^{Distributors} + \textit{Stretch Factor}.$$

A more complicated scale escalator could also be considered that addresses, additionally, growth in distribution line miles. The weights for such an index can be obtained from econometric research on the drivers of power distribution cost.

Distributors operating under index-based ARMs can nonetheless experience considerable volatility around long term productivity trends due to occasional cost surges. There are ways to keep HQD's operating risk within acceptable bounds.

- Weather normalization (under price caps) or revenue decoupling

- Earnings sharing and off ramp provisions
- Trackers for volatile costs that HQD can't control
- Cumulative revenue escalation restrictions that would permit HQD to obtain supplemental revenue for a cost surge in some years provided that revenue grew more slowly in other years of the plan term.

Independent productivity trend research should be commissioned in Phase 2 to inform the design of the ARM. Trends in the productivity of O&M and capital inputs should be calculated as well as the trend in multifactor productivity. In addition to its usefulness in an index-based ARM, O&M productivity results can be used to design the O&M escalator in a hybrid revenue cap and/or a productivity-based formula for forecasting O&M expenses that is useful in an all-forecast ARM.

Research should ideally be conducted on the productivity trends of both HQD and a large sample of US power distributors. A study of US trends is the more essential of these two as those trends provide the essential external productivity growth standard. It is as yet uncertain whether HQD's data permit accurate estimation of its productivity trends. The suitability of these data should be established in Phase 1 via data requests. The Phase 2 study should, additionally, consider an appropriate inflation measure for HQD's ARM and survey energy distributor X factor precedents and credible studies of energy utility productivity trends in Canada.

We also encourage the Régie to commission an independent transnational statistical benchmarking study of HQD that can provide input on the appropriate stretch factor. Econometric research used to develop ARMs reduces the incremental cost of a cost benchmarking study. Econometric benchmarking studies are favored by regulators in a number of jurisdictions. We believe that independent benchmarking studies are much more effective at establishing the truth about a utility's operating performance than a critique by Régie staff and intervenors of utility-commissioned studies.

US data are the best for an econometric benchmarking study of HQD because they are standardized and available for many years for a large number of power distributors facing diverse operating conditions. Advantages of US capital cost data were noted in Section 4.5.2

above. The Ontario Energy Board recently commissioned an independent transnational cost benchmark study using US data in a recent custom MRP proceeding for Toronto Hydro.

The benchmarking study can address the Company's reliability as well as its cost provided that HQD can provide standardized reliability data. A reliability benchmarking study is useful for ascertaining whether standards are too low or high and can provide the basis for separate reliability standards for the urban and rural areas that HQD serves.

<u>Transmission</u>

As for HQT, the Company's revenue requirement history does not provide pronounced evidence of a "stairstep" cost trajectory that might be better addressed by a hybrid ARM. The HQT system may be too large and diverse for particular capex projects to have a large impact. This is an argument favoring an index-based escalator. We believe that an index based ARM should be "Plan A" for HQT given its advantages.

An index-based revenue cap for HQT would have the general form

$$\textit{growth Revenue}^{HQT} = \textit{Inflation} - X + \textit{growth Scale}^{HQT} + Y + Z$$

$$X = \textit{Base Productivity Trend}^{Transmission} + \textit{Stretch Factor.}$$

The scale index would likely be multidimensional. Weights can be obtained from econometric research on transmission cost. Candidate variables for the scale index include scale-related cost drivers like transmission line miles and Québec's generation capacity. Peak demand growth is another major cost driver for transmission utilities but inclusion of this variable would reduce the incentive to contain peak demand growth. It makes sense to instead include one or more variables in the scale index which drive peak demand growth such as the number of retail customers in the province. Using data on the operations of US utilities, we have undertaken preliminary econometric research that suggests that we can obtain sensible and statistically significant weights for a transmission scale index that is serviceable for a revenue cap index for HQT.

Indexing research can provide the foundation for an index-based ARM for HQT. It is also useful in the design of index-based escalators for O&M revenue in hybrid ARMs and index-based forecasts of O&M expenses in all-forecast ARMs. An independent productivity study is therefore desirable for power transmission in Phase 2 as well. Trends in the O&M, capital, and multifactor productivity of transmission utilities should be addressed in this study as well.

The Phase 2 study should, if HQT's data permits, consider the division's productivity trends as well as the trends for a large sample of investor-owned US power transmission utilities. The suitability of HQT's data for such an exercise is uncertain and should be clarified in Phase 1 data requests. The Phase 2 study should also consider appropriate inflation measures for an index-based ARM for Québec transmission. Finally, the study should survey transmission productivity studies from respected sources in the academic literature and regulatory proceedings. We also encourage the Régie to commission an independent statistical cost benchmarking study of HQT that can be useful in setting its stretch factor. Econometric research required for index development reduces the incremental cost of a benchmarking study.

The year to year growth of HQT's forecasted revenue requirement nonetheless varies materially from the gradual trend in revenue growth that would likely be provided by an index-based escalator. According to HQT's forecasts, growth is likely to be more rapid in the early years of the 2018-21 period and slower in the later years. This situation could be addressed by a capital cost tracker for one or more major projects, already approved, that give rise to the early cost surge. Alternatively or in addition, HQT could be permitted to borrow from future revenue escalation allowances.

Should an index-based escalator prove unsuitable for HQT, a hybrid approach to ARM design also merits consideration. Revenue for O&M expenses would be indexed, while revenue for capital costs would be forecasted. Capex budgets could be approved in real terms and then escalation for Canadian transmission construction costs. The weighted average cost of capital could be adjusted annually using a "new and improved" index of market rates of return. The argument against the hybrid approach is the difficulty of appraising HQT's capital cost forecasts. It would be desirable to simplify the capex forecasting task by using sensible formulas for some capex categories.

6.2.4 Cost Trackers

Y Factors for HQD

Power supply and transmission costs paid by HQD to other service providers should be Y factored. Review of HQD's power supply costs should intensify. Arrangements for new supplemental power supplies would be a key focus of hearings. Demand side alternatives to proposals to increase supplemental supplies should be addressed in hearings. Consideration should be paid to permitting third parties to present alternative power supply proposals. A reduction in the frequency of rate cases would free up more resources to address this important issue.

While more effort in a traditional review of HQD's power supply costs should produce better results, steps should be taken to strengthen HQD's incentive to contain these costs. One possible approach is to incentivize the power supply cost tracker. Revenue/MWh could, for example, be based b% on HQD's actual cost and (1-b)% on its forecasted cost.

HQD will likely press for the tracking several other costs, including costs that it currently tracks. We recommend that the Régie should err on the side of rejecting these requests. Reasonable candidates for Y factoring include the following:

- Severe storm expenses
- Changes in utility accounting standards
- Expiration of the amortization of deferral accounts.
- CDM expenses

Y Factors for HQT

Very few of HQT's costs are currently subject to tracker treatment. The division will likely press for these and other costs to be tracked. We recommend that the Régie err on the side of rejecting these requests as well.

Reasonable candidates for Y factoring include the following:

- Severe storm expenses
- Changes in utility accounting standards
- Expiration of the amortization of deferral accounts.

Capital Cost Trackers

We do not believe that HQD needs a capital cost tracker in the first plan period. HQT, in contrast, might need the option of requesting tracker treatment for some projects if an index-based ARM is developed. This proposed treatment would be similar to the Ontario Energy Board's Incremental Capital Module.

If the Régie permits either division to request capital cost trackers, the following design issues must be addressed.

Eligibility Requirements Capex eligible for tracker treatment should be strictly limited. The Commission should formulate clear eligibility guidelines. For example, capex should be more eligible for tracker treatment to the extent that it is large, extraordinary, and likely to prevent an efficient utility from attaining its allowed ROE on average during the plan period.

Evidentiary Requirements Minimum filing requirements should be established for capital cost tracker requests. The salient alternatives to the proposed capex, including CDM options, should be addressed by the applicant. Other parties should be permitted to propose alternative solutions.

The procedure for approving the reasonableness of proposed large plant additions should be strengthened, ideally by moving to a public process of integrated distribution and transmission planning that considers CDM options. An increase in the minimum dollar amount of capex eligible for review should be considered.

Incentivization Provisions Capital cost trackers should be incentivized. Deviations between forecasted and actual costs can be shared automatically in a certain range. Large cost overruns may be subject to prudence reviews and delayed recovery. HQ's reward for an in service date later than forecasted or for postponing a project proposed for tracking should not exceed a share of the (typically modest) value to customers of deferring the project.

Double Counting Provisions We noted in Section 5 that many capex costs for which tracker treatment is sometimes requested are incurred routinely by utilities and slow growth in their multifactor productivity. This lowers the base productivity growth target in an index-based ARM and thereby speeds revenue growth. Expedited recovery of these costs through trackers can therefore result in a double counting that deprives customers of MRP benefits. Here are three ways to reduce the double counting problem in Québec.

- An historical review window can be used for recovery of tracked capital cost. Under this approach, recovery of tracked cost would begin in the year after it becomes used and useful.
- Costs of a particular capex project that are tracked in one MRP can be tracked in subsequent MRPs. This ratemaking treatment would pass through to customers the full benefit of the gradual depreciation of targeted assets once they are used and useful. Tracking the cost of older plant is straightforward. Costs of older plant are routinely subject to tracker treatment in British Columbia MRPs.

- The base productivity growth trend can be escalated in recognition of the fact that some capex that is routinely incurred by utilities in the productivity peer group is being tracked in the MRP of the subject utility.

Z Factors

For both companies, some hard to foresee costs warrant consideration for Z factor treatment. Eligibility for Z factor treatment should be limited. Materially thresholds should be high, and pertain to *each incident* so that the utility is not incentivized to compile numerous small incidents.

6.2.5 Earnings Sharing and Off Ramps

Earnings sharing is one of the most difficult decisions in ARM design. On the one hand, an earnings sharing mechanism can reduce the risk that revenue will deviate significantly from cost. The reduction in risk can make it possible to extend the period between rate cases. Customers share in the benefits of the deferral of recurrent costs. On the other hand, our incentive power research showed that an earnings sharing mechanism weakens utility performance incentives. The provision of marketing flexibility is complicated since discounts to some customers can affect the earnings variances distributed to all customers. Regulatory cost is raised. On balance, we believe that an ESM makes sense for first-generation MRPs. Performance incentives can be strengthened by adding a modest dead band to the mechanism.

Similarly, it makes sense for first generation MRPs to include off ramp provisions. The need for off ramps is reduced by the proposed earnings sharing mechanism. Furthermore, we have noted that utilities operating under MRPs should expect some earnings volatility. The rate of return on equity should therefore deviate quite significantly from the Régie approved target before an off ramp is triggered. A representative rule might be that the plan would be reviewed if the average deviation of the rate of return over three years exceeded 300 basis points.

6.2.6 Incentive-Compatible Menus

Incentive-compatible menus were noted in Section 4.2.5 to be a promising tool for MRP design. Menu options typically vary with respect to a key ARM provision, such as the X factor or average revenue requirement, and another financially important provision such as the division of earnings variances between the utility and its customers in earnings sharing mechanisms. Menus can be designed for indexed, forecasted, and hybrid ARMs.

We recommend that the Régie consider use of incentive-compatible menus in this and future plans. It must be emphasized, however, that development of menus that share value with customers is costly since it requires the Régie to develop reliable independent views on efficient costs and cost trends. The Régie may not develop this capability in the course of this proceeding. The ability to adopt incentive compatible menus in the future will be bolstered to the extent that the Régie takes steps soon to encourage independent engineering and benchmarking studies and stronger, more integrated capex and power supply planning procedures.

6.2.7 Performance Metric Systems

Both plans should have extensive performance metric systems. In these systems, some metrics should have only targets whereas others should be used in performance incentive mechanisms.[78] A short list of the more important metrics should be featured in a scorecard that is posted electronically by the Régie or Hydro-Québec for the public to see. PIM calculations should be externally audited. Reliability goals should be carefully considered, since high reliability is costly.

Due to the stronger cost containment incentives generated by MRPs, both divisions should have PIMs for reliability, customer service quality, and worker safety. Reliability PIMs for distribution should include SAIDI and SAIFI. To facilitate comparability with reliability data from other utilities, reliability metrics should conform to the IEEE 1366 standard.

Reliability metrics should include more granular measures. For HQD, more granular measures might include reliability in rural areas and on worse-performing circuits. For HQT, reliability and customer satisfaction measures should if possible be reported separately for HQP and the independent power marketers. Some service quality penalties may be paid directly to affected customers. The Régie may in certain cases prefer to use the occasion of demonstrably poor quality to order its rectification instead of levying a penalty.

One or more PIMs should, additionally, provide additional rewards to HQD for good peak load management. These would ideally consider peak load savings at the aggregate level. HQD could be rewarded for documented success at reducing peak load. Its reward could be a

[78] Additionally, some might have no targets.

share of documented distribution, transmission, and power supply savings. Distribution capex savings from particular local projects could be rewarded in the manner of the Brooklyn Queens Demand Management project. Market transformation is further encouraged if a PIM can be devised that encourages CDM from all sources.

We discussed in Section 6.2.4 the option of an incentivized cost tracker for HQD's power supply expenses. An alternative means of strengthening the division's incentive to contain these expenses is to establish a PIM for power supply costs. We have noted that PIMs of this kind have been used many times in the regulation of the gas procurement expenses of natural gas distributors. To reduce the risk of volume fluctuations, the PIM could pertain to expenses per kWh of power purchases. The focus can be on the unit cost of total power supplies or the unit cost of new incremental supplies. Since power procurement is risky, consideration could be paid to a PIM that asymmetrically rewards good performance. For example, HQD could earn a reward if it avoided the need for incremental power supplies.

Given the government's interest in cost reduction, it would be desirable as well for HQ to report certain cost performance metrics routinely. For example, the divisions could annually report their multifactor productivity growth in addition to unit cost metrics like those the divisions currently report. Consideration should be paid to unit cost metrics based on multidimensional scale indexes (e.g., one summarizing distribution line miles and customers).

Here are some additional metrics that merit consideration for inclusion in the performance metric system without financial ramifications include the following.

<u>AMI</u> Several metrics may be desirable to monitor whether HQD's advanced metering infrastructure is used and useful. These might include measures of metering accuracy, defective meters, customer complaints with meters, and the number of customers accessing hourly load data and/or enrolled in time-sensitive pricing programs.

<u>Third Party Cooperation</u> Metrics may address cooperation of HQD with efforts by third parties to provide CDM and EV services.

<u>Transparency</u> To reduce information asymmetry in hearings, the number of times a division was ordered by the Régie to improve its response to a data request should be monitored.

<u>Electric Vehicles</u> Growth of electric vehicle customers and load should be monitored, along with related metrics such as commercial charging stations owned by HQT and other parties. Total EV load may merit a PIM if EV service isn't price capped.

Environment Metrics monitoring the environmental impact of HQD should continue.

Table 3 provides a summary of our performance metric system recommendations.

Table 3

Performance Metric System Recommendations

	Performance Incentive Mechanisms	Other Metrics
	Distribution	
Reliability	SAIDI (IEEE 1366 standard, rural & urban) SAIFI (IEEE 1366 standard, rural & urban)	Worst performing circuits MAIFI
Customer Service	Telephone response time Appointments kept Timeliness of connections	Customer satisfaction Customer complaints Invoice accuracy
CDM	Peak load savings	Conservation savings CDM expenses Customers enrolled in CDM programs
Safety	Worker safety	Deaths from electrocution in general population
Cost	Power Supply Cost	O&M, capital, and multifactor productivity indexes Unit cost metrics (O&M, total cost, losses) Consumption on inactive meters
Other		Electric Vehicles AMI used & useful (e.g., customer engagement) Third party cooperation Transparency in regulation
	Transmission	
Reliability	Frequency (normalized) Duration (normalized)	Frequency detail for point to point customers Duration detail for point to point customers Equipment failures
Customer Service	On time connections Miscellaneous	Customer Engagement Compliance with established standards Customer satisfaction (Independent point to point customers itemized)
Safety	Worker safety	
Cost		O&M, capital, and multifactor productivity indexes Unit cost metrics (O&M, total cost, losses)
Other	Selected environmental metrics	Other environmental metrics Transparency in regulation

6.2.8 Marketing Flexibility

Marketing flexibility provisions should permit a continuation of the economic development and load retention rates. If service to large load customers is subject to price caps, there is no need to recover load retention discounts from other customers between rate cases.

Both divisions should, additionally, be permitted to gradually redesign tariffs during the term of the plan to achieve any Régie-approved goals. An example for HQD might be the phase in of time-sensitive usage charges, in standard tariffs for residential and commercial customers, which discourage system use in peak hours.

Both divisions should also be permitted to provide certain optional tariffs to customers who retain recourse to service under standard tariffs. One eligible optional tariff for HQD might feature time-sensitive pricing for residential and commercial customers. Another might encourage commercial customers to use electricity off-peak for space heating. Time-sensitive pricing should be required for electric vehicle customers.

6.2.9 Plan Termination Provisions

Given the lack of experience with MRPs in Québec, we recommend relatively short four year terms for both companies in the first plan. The incentive power of such plans should be considerably greater than annual rate cases. Mid-term review of each plan would be undertaken in the third year. This review would consider trends in the utility's cost efficiency (with special attention to deferrable costs), CDM, marketing flexibility, service quality, and earnings and the regulatory cost savings achieved. The midterm review should have the possible outcome of a plan update and extension.

Efficiency carryover mechanisms should be considered for each company. Existing ECMs in Alberta and Australia unfortunately do not provide good starting points for a Québec mechanism and fresh thinking is needed. Mechanisms should be designed to reward good value to customers in the rates of future MRPs rather than focusing on cost savings in the expiring MRP.

6.2.10 Autonomous Networks

Given its modest share of HQD's total cost and the sizable potential cost of designing an MRP for service in such unusual systems, we recommend that the cost of autonomous networks should be addressed in the main MRP for HQD. Y factoring of the costs of autonomous networks should be kept to a minimum to strengthen incentives for cost containment. The price of diesel fuel in Québec can be included in the inflation measure. The cost of autonomous networks should be removed from HQD's cost if these costs are benchmarked.

6.2.11 Procedure for Approving Plans

MRPs reduce regulatory cost chiefly by reducing the frequency of rate cases. Development of plans that can successfully replace several years of rate cases nonetheless involves sizable regulatory cost. Extra "startup" costs" can be expected in early MRP cycles. It is unwise to slash rate case costs *and* typical MRP development costs, especially in a first generation plan.

We therefore hope that the Régie is prepared to make a sizable investment in this proceeding to develop new approaches to T&D regulation. In addition to independent productivity trend studies, there should be statistical benchmarking studies of each division's recent historical costs and the costs forecasted for the 2017 test year. The Régie should also consider hiring independent engineering consultants or developing additional in house expertise to develop better independent views of the capex requirements of the two divisions.

One means of making the regulatory burden of rate cases and MRP development more manageable is to have them start in different years. The regulatory community would then be able to focus on one rate case and MRP at a time. The Régie could then apply lessons learned in processing the application for one division when it turns to the application of the other division. The benefit of this approach is all the greater considering that individual rate cases will be more complicated when held only once every 4-5 years.

6.2.12 Summary

A brief summary of our proposed recommendations can be found in Table 4.

Table 4-Revised

Summary of Incentive Regulation Recommendations

	HQD	HQT
Basic Approach to Incentive Regulation	Multiyear rate plan	Multiyear rate plan
Revenue Caps or Price Caps	Revenue caps for most customers Price caps for industrial customers	Revenue caps
~~**Revenue Caps or Price Caps**~~	~~Revenue caps~~	~~Revenue caps for most customers~~ ~~Price caps for industrial customers~~
Relaxing the Revenue/Usage Link	Revenue decoupling for small volume customers LRAMs for large volume customers	Revenue decoupling
~~**Relaxing the Revenue/Usage Link**~~	~~Revenue decoupling~~	~~Revenue decoupling for small volume customers~~ ~~LRAMs for large volume customers~~
Attrition Relief Mechanism	Indexation	Indexation preferred: Hybrid is fallback
Phase 2 Studies	Productivity & Benchmarking	Productivity & Benchmarking
Y factors	Power Supply, Transmission, CDM	Limited Capital Cost Option if ARM is indexed
Z Factors	Yes	Yes
Incentive Compatible Menus	Worthwhile for both, but may be premature. Independent forecasting must improve.	
Performance Incentive Mechanism	Reliability Safety Customer Service Power Supply Cost Peak Load Management	Reliability Safety Customer Service Environment
Earnings Sharing Mechanism	Yes	Yes
Off Ramps	Yes	Yes
Marketing Flexibility	Yes	Yes ~~No~~
Plan Term	4 years	4 years
Regulation of Autonomous Systems	Included in Plan	Not applicable

Pacific Economics Group Research, LLC

Appendix

A.1 Glossary of Acronyms

ARM	Attrition relief mechanism
ECM	Efficiency carryover mechanism
Capex	Capital expenditures
CDM	Conservation and demand management
CMP	Central Maine Power
EV	Plug in electric vehicle
FERC	Federal Energy Regulatory Commission
HQD	Hydro-Québec Distribution
HQT	Hydro-Québec Transmission
HQP	Hydro-Québec Production
IEEE	Institute of Electrical and Electronic Engineers
IQI	Information Quality Incentive
LRAM	Lost revenue adjustment mechanism
MFP	Multifactor productivity
MRP	Multiyear rate plan
MW	Megawatts
MWh	Megawatt hours
O&M	Operation and maintenance
PEG	Pacific Economics Group Research, LLC
PIM	Targeted performance incentive mechanism
ROE	Rate of return on equity
T&D	Transmission and distribution
Y	Y factor (adjust rates for targeted costs selected in advance)
Z	Z factor (adjust rates for miscellaneous other developments)

A.2 Insights from Incentive Power Research

PEG Research has for many years undertaken research on the incentive power of alternative regulatory systems. The work has been sponsored by numerous utilities and regulatory agencies, including two Canadian gas distributors, the Ontario Energy Board, and the state of Victoria, Australia's Essential Services Commission. Incentive power research can be used to explore MRP design options such as efficiency carryover mechanisms. 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 University of Texas.

This Appendix section first presents a non-technical discussion of the methods used in our incentive power research. We then discuss research results.

A.2.1 Overview of Research Program

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 that resemble those of a large energy distributor. In the first year of the decision problem, the total annual cost of the company is around $500 million for a company of average efficiency. Capital accounts for a little more than half of the total cost of base rate inputs. The annual depreciation rate is 5%, the weighted average cost of capital is 7%, and the income tax rate is 30%.[79]

Some assumptions are made to simplify the analysis. There is no inflation or output growth that would cause cost to grow over time. Under these assumptions, the utility's revenue will be the same year after year in the absence of a rate case. There is thus no need for complicated adjustments in rate cases to the costs incurred in historical reference years or for attrition relief mechanisms between rate cases.

The company has opportunities to reduce its cost of service through cost reduction effort. 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

[79] The comparatively low WACC reflects our assumption that there is no input price inflation.

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, respectively. For projects of each kind, there are diminishing returns to additional cost reduction effort in a given year. In total, we currently consider eight kinds of projects, four for O&M expenses and four for capex. The company is permitted to pass up each kind of project in a given year but cannot choose *negative* levels of effort that amount, essentially, to deliberate waste. This is tantamount to assuming that deliberate waste is recognized by the regulator and disallowed.

Companies can increase earnings by undertaking cost containment projects, but the company experiences employee distress and other *unaccountable* costs when pursuing such projects. These costs are assumed for simplicity to occur up front. We have assigned these a value, in the reckonings of employees, 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 in a given year, less the distress costs of performance improvement, given the regulatory system, the income tax rate, and the available cost reduction opportunities. We are interested in examining how the company's cost management strategy differs under alternative regulatory systems.

Regulatory Systems

Regarding the regulatory systems considered, we have developed five "reference" systems that constitute useful comparators for MRPs. One is "cost plus" regulation, in which a company's revenue is exactly equal to its cost. Another is a full externalization of rates, such as might obtain if the company were to embark on a permanent revenue cap regime with no prospect for future cost-based revenue requirement true-ups.

The other three reference regimes try to approximate traditional regulation. In each, there is a predictable rate case cycle. We consider rate case cycles of one, two, and three years.

Various MRPs can be considered using our research method. All are revenue cap plans. The plans differ with respect to three kinds of plan provisions. One is the term of the plan. We consider terms of six and ten years. There is no stretch factor shaving the revenue requirement mechanistically from year to year.

Plans considered vary, secondly, 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 0%, 25%, 50%, and 75%. We will refer to a rate plan that lacks an earnings sharing mechanism as a "basic" rate plan. None of the mechanisms considered have dead bands, as these complicate the calculations. This limits the relevance of the results since many approved mechanisms do have dead bands.

Our characterization of the rate case is important in modeling both traditional regulation and the MRP regimes. We assume in most 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. The qualification is that any up front *accountable* costs of initiatives for sustainable cost reductions that are undertaken in the historical reference year are amortized over the term of the plan. This reduces the incentive for the utility to time cost reduction projects to occur in the reference year. We consider, additionally, an alternative rate case specification that differs only in that *all* years of the previous rate plan are treated as reference years and the revenue requirement is based on the average cost achieved.

We have also considered the impact of some stylized efficiency carryover mechanisms. In one mechanism we have examined the revenue requirement at the start of a new plan is based $\alpha\%$ on the cost in the last year of the previous plan and $(1-\alpha)\%$ on the revenue requirement in that year. This effectively permits the company to share $(1-\alpha)\%$ of any deviation between its cost and the revenue requirement. We consider alternative values of α, ranging from 90% to 50%.

We also 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 resulting from a benchmarking appraisal that is completely unrelated to past revenue requirements. We suppose that

$$Requirement_t = Cost_{t-1} + Carryover_{t-1}$$

where the carryover is $\alpha\%$ of the difference between a benchmark for cost in period t-1 and the actual cost that was incurred.

$$Carryover_t = \alpha \times (Benchmark_{t-1} - Cost_{t-1})$$

Then

$$Requirement_t = Cost_{t-1} + \alpha \times (Benchmark_{t-1} - Cost_{t-1})$$

$$= \alpha \times Benchmark_{t-1} + (1-\alpha) \times Cost_{t-1}$$

The revenue requirement for the first year of the new PBR plan thus depends only (1-α)% on the cost of service in year t-1. 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.

We have also considered a novel approach to incenting long term efficiency gains which we will call the "revenue option" approach. It gives the company the option to trade a revenue requirement, for the first year of the next rate plan, which is established by conventional means for a revenue requirement that is established on the basis of a predetermined formula. The formula that we consider is a stretch factor reduction in the revenue requirement that is established in the first year of the preceding rate case.[80]

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.

One advantage of numerical analysis in this application is that it permits us to consider regulatory systems of considerable realism. Another is that it facilitates review of our research by stakeholders. The numerical analysis is intuitively appealing, and verification can focus less on how results are derived and more on how sensible and thorough is our characterization of cost containment opportunities and alternative regulatory systems.

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

A.2.2 Research Results

A summary of results from the incentive power model is found in Tables A1-A3. For each of several regulatory systems, the table shows 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 table we report the average percentage reduction in the company's total cost that results from the regulatory system. We report outcomes for the first plan, the second plan, and the long run and discuss here only the long run results. Results are presented for 10%, 30% and 50% levels of initial operating efficiency. We focus here on the 30% results since research suggests that this is a normal level of operating efficiency. The 30% results can be found in Table A1.

Results for Reference Regulatory Systems

Inspecting the results for the reference regulatory systems, it can be seen that no cost reduction initiatives are undertaken under cost plus regulation. This reflects the fact that there is no monetary reward for undertaking the cost reduction initiatives, all of which involve some kind of cost. At the other extreme, a complete externalization of future rates produces performance improvements relative to cost plus regulation that, over many years, accumulate to an NPV of more than $2 billion.

As for the traditional regulatory systems, it can be seen that 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 those that are potentially available. Average annual productivity gains rise from 0% to 0.90%, a gain of about 90 basis points. The fact that some cost savings occur under traditional regulation isn't 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.

Impact of Plan Term

Consider now the effect of extending the plan term beyond the three year rate case cycle. It can be seen that extending the term from three years to six increases cost savings in the long term by about 59%. Average annual productivity growth rises by an incremental 68 basis points, to 1.58% per annum. Extending the term from three years to ten increases cost savings by about 85%.

Table A1

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 A2

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 A3

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 Earnings-Sharing

With respect to earnings sharing note first that, in plans of a given duration, the addition of earnings sharing mechanisms reduces cost savings modestly compared to a plan of the same duration with no sharing mechanism. The lower is the company's share of earnings variances, the lower are cost savings. However, plans of longer duration that *have* an earnings sharing mechanism can deliver more cost savings than plans of shorter duration that *lack* an earnings sharing mechanism. For example, a five year plan with 50/50 sharing produces 7% more cost savings than traditional regulation with a three year cycle.

Impact of Multiple Historical Reference Years

Consider, next, what happens when a rate case bases the new revenue requirement on multiple historical reference years instead of just the last year of the rate case plan. In the case of a three year regulatory cycle, the long run cost savings rise by a surprising 50% and are larger than those from a basic five year rate plan with traditional rate cases. Using multiple reference years in a five year plan increases cost savings by a smaller 20% because there are fewer unrealized savings.

Impact of Revenue Requirement Benchmark

Let's consider now the impact of the efficiency carryover mechanism that uses the predetermined revenue requirement from the previous plan as the benchmark. It can be seen that, in the context of a three year rate plan, assigning the benchmark a weight of only 25% produces 49% more cost efficiency gains. The gain when compared to a basic five year cycle is a more modest but still substantial 21%. The reduced payoff is mainly due to the fact that more of the potential cost savings are achieved by the five year term. It appears that this kind of ECM has the potential to strengthen performance incentives substantially.

Impact of Efficiency Carryover Mechanism With Fully External Benchmark

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, it can be seen that assigning the benchmark a weight of only 25% more than doubles the cost savings produced by three year COSR cycles. This suggests that benchmarking has the potential to strengthen performance incentives rather dramatically. With a five year rate case cycle, the effect of the same 25% 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 Revenue Option Efficiency Carryover Mechanism

Let's turn now to the impact of the rate option approach to efficiency carryover mechanism design. It can be seen that for stretch factors of 1%, 1. ~~2~~5%, and ~~1.5~~2.0%, the rate option approach produces the same dramatic cost efficiency savings that would result from full rate externalization. Cost efficiency growth averages 2.71% annually in the long run. 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

We believe that our incentive power research has yielded important results on the consequences of alternative regulatory systems. Most fundamentally, the results show that the design of a PBR plan can have a major impact on utility performance. Generally speaking, incentives are strengthened by longer plan terms and by ECMs and other schemes to share long term performance gains.

A.3 Minimum Filing Requirements: Example from New Jersey

New Jersey

In New Jersey the use of distribution system improvement charges ("DSICs") for water utilities was sanctioned in 2012 complete with requirements for both the foundational filing and tracker implementation. The relevant sections of New Jersey's Administrative Code outlining the foundational filing requirements are provided below.[81]

14:9-10.4 DSIC foundational filing

(a) The Board shall authorize the implementation of a DSIC by a water utility. Under the DSIC, the Board shall authorize a water utility to recover costs associated with DSIC-eligible projects through an approved DSIC rate.

(b) To obtain authorization to implement a DSIC, the water utility shall submit a foundational filing to the Board. Whether filed separately or concurrently with a base

[81] New Jersey Administrative Code, N.J.A.C. 14:9-10.4.

rate case, the water utility shall submit with the foundational filing, certain information, described below:

1. An engineering evaluation report of the water utility's distribution system that:

i. Identifies the rationale for the work needed to be accelerated for the water utility to properly sustain its water distribution network;

ii. Demonstrates that the plan proposed to accelerate the renewal of the distribution network is the most cost effective plan;

iii. To the extent that elements of the distribution network are failing, identifies what mechanisms are causing the failures; and

iv. Identifies what is being done to extend the life of the water utility's distribution network assets;

2. DSIC project information for the upcoming DSIC period that includes the following:

i. A list of projects, DSIC-eligible asset class, or category;

ii. The nature, location, estimated duration of project work (including estimated in-service dates), and a description and reason for project necessity;

iii. Aggregate information capturing blanket-type, DSIC-eligible infrastructure, to be rehabilitated or replaced (that is, number of valves, hydrants, or service lines) and the estimated annual cost of such blanket-type replacement programs;

iv. Vintage, condition, or other similarly relevant, reasonably available information about the eligible infrastructure that is being rehabilitated or replaced;

v. Estimated project costs;

vi. Project identification numbers, so DSIC projects can be easily tracked; and

vii. Other such information, as is relevant and appropriate, in order to provide adequate information to make an informed decision regarding any given project; and

3. The expected amount of base spending for the water utility, including underlying detail adequate to document that the base spending has been made on the appropriate types of infrastructure including, a proposed DSIC assessment, calculated in accordance with N.J.A.C. 14:9-10.8 and work papers showing the detailed calculations supporting the proposed assessment schedule.

4. A public notice and hearing, at a minimum, are required in the DSIC foundational filing. The hearing notice shall include the maximum dollar amount allowable for recovery between rate cases, as well as an estimated rate impact for the entire period on customers.

5. After a foundational filing has been approved by the Board, a water utility may request that a different DSIC-eligible project be substituted for one already approved by the Board. The water utility shall submit written notice to the Board and the Division of Rate Counsel, identifying the project and detailing the reason(s) for the requested change, for approval.

6. DSIC rates shall be rolled into base rates during a water utility's subsequent base rate case. All new foundational filing must be approved before new DSIC investment and DSIC rate recovery may occur.

(d) When a water utility has its DSIC rate reset to zero, a new foundational filing must be approved before new DSIC investments and DSIC Rate recovery may occur.

A.4 Examples of Capital Tracker Rejections[82]

Given the need for quality evidence in support of accelerated modernization programs it is instructive to examine instances where such programs were rejected. We provide here several case studies.

Peoples Gas

Peoples Gas Light & Coke ("Peoples") serves the city of Chicago. Its system contains cast iron mains that are over a century old. Many meters are located inside customers' homes.

The Company had a capital tracker proposal to accelerate its mains replacements rejected in its 2007 rate case. One reason for the rejection was that Illinois has a very strict limitation on single issue ratemaking. Since accelerated main replacement was shown to create some cost savings, this hurdle could not be overcome. Another concern was that Peoples had not guaranteed that an accelerated level of replacements would be made. The Illinois Commerce Commission ("ICC") also took exception to the evidence of need. The critique by the ICC is sufficiently insightful to merit quoting at some length.

> The Commission is cognizant of the potential benefits of an accelerated CI/DI main replacement program. To be sure, the Commission is keenly aware of the critical need

[82] These examples were previously presented in the testimony of Dr. Lowry in an Alberta MRP proceeding.

to update and replace the infrastructure that we depend on to deliver our nation's natural gas and energy supply. Unfortunately, in this particular instance, Rider ICR is a deficient vehicle for such a goal. As Staff aptly points out, proposed Rider ICR provides no estimate of the costs or savings under the accelerated program, nor does it demonstrate that the savings will outweigh the additional costs paid by ratepayers under the proposed rider. Staff Ex. 8.0, pp.36-37. Given the paucity of Rider ICR's provisions, the Commission must reject it….

This rider proposal reflects a need for the Commission to provide guidance to utilities on the information the Commission needs, at a minimum, to evaluate system modernization proposals, beyond Part 656 and Section 220.2 of the Act. Peoples Gas presented this Commission with no quantitative evidence, no benefit-cost analysis, and no plan as to why or how a $1.0 billion dollar, forty- to forty-five- year investment, should be completed at a much faster rate (i.e., within the next seventeen to twenty-two years).

And yet, we suspect that there are many benefits – quantitative and qualitative – that could have been identified, enumerated and quantified in support of an enhanced system modernization initiative. It is our view that Peoples Gas could have quantified the benefits of Rider ICR. Absent a clear evidentiary record which demonstrates the benefits of the Rider ICR, the Commission must reject the proposal.

So, we are left with a dilemma. To ensure continued reliability, we lean towards increased system modernization, rather than less, all other things being equal. In a general sense, the application of modern technology to the utilities and networks that we regulate and upon which our economy depends makes simple common sense. But unless the proponents of the modernization initiatives provide a more compelling rationale in terms of identifying and quantifying reduced system costs and increased customer benefits, we will never be persuaded that modernization is in the best interest of the ratepayers. Thus, we are likely to have less system modernization in Illinois, rather than more, and the consumers and businesses in Illinois will be the worse for it.

In the case of Rider ICR, the Utilities' proposal is insufficient for the Commission to approve it. It might have been easier to approve the rider had the Utilities included, or the Staff or the Intervenors' elicited, such information as: a detailed description and cost analysis of the proposed system modernization; an identification and evaluation of the range of technology options considered and analysis and justification of the proposed technology approach; a detailed identification and description of the functionalities of the new system, related both to system operation as well as on the customer side of the meter, as well as an identification and justification of functionalities foregone; analysis of the benefits of the system modernization, both to system operation as well as to customers; these benefits should include reductions in system costs as well as an analysis of the range and benefits of potential new products and services for customers made possible by the system modernization; an analysis of regulatory mechanisms to allow companies to

> both recover their costs of system modernization as well as to flow reduced system costs back to customers; and an identification and analysis of legal or regulatory barriers to the implementation of system modernization proposals.[83]

In a subsequent 2009 rate case the ICC approved the company's proposed capital tracker for accelerated main replacement called Rider ICR.[84] Two intervenors, the City of Chicago and Peoples' union, supported the tracker in this proceeding. In this order, the ICC laid out with specificity several standards that were required to approve a capital tracker for accelerated system modernization. These included the following.

> Standard No. 1 – A detailed description and cost analysis of the proposed system modernization.

> Standard No. 2 – An identification and evaluation of the range of technology options considered, and an analysis and justification of the proposed technology approach.

> Standard No. 3 – A detailed identification and description of the functionalities of the new system (related to both system operation as well as on the customer side of the meter), and, an identification and justification of the functionalities foregone.

> Standard No. 4 – Analysis of the benefits of the system modernization, both to system operation as well as to customers (including reductions in system costs, and an analysis of the range and benefits of potential new products and services for customers made possible by the system modernization).

The ICC ruled that Peoples met the first standard by presenting testimony by an independent engineering expert who analyzed the state of the company's system and provided a detailed cost analysis quantifying the costs and benefits of the company's proposed accelerated plan against the current replacement program and other alternative accelerations of its plan. Peoples also showed that there were economies of scale and scope possible with a larger replacement program that would allow it to work in zones rather than on an as-needed basis. The larger scale would also allow better coordination with other utilities and the City of Chicago which would also help to reduce costs.

Peoples met the second standard by describing the pipes that were to be installed as well as new drilling technologies and main alignments that would provide benefits. Peoples met

[83] Illinois Commerce Commission, February 5, 2008 Order in Case 07-241/07-242, p. 161-162.
[84] The Illinois Commerce Commission's order approving the tracker was later overturned by an Illinois court.

the third standard by describing how the system would be simpler, more reliable, and optimally designed with no loss in functionality, less water infiltration, and fewer meters inside homes. Peoples met the fourth standard via the cost analysis mentioned above but listed further benefits to its plan. Benefits identified by Peoples included quantified O&M cost savings, a reduction in the number of leaks caused by corrosion, a reduction in potential property damage in the case of gas leaks, reductions in customer inconveniences caused by in-home meters, elimination of customers using gas pressure booster systems, environmental benefits through greater use of gas, a reduction in greenhouse gas emissions, and the creation of jobs.[85]

Western Massachusetts Electric

Western Massachusetts Electric had a capital tracker called the Capital Reliability Reconciliation Clause ("CRRC") rejected in its 2010 rate case. The tracker was rejected primarily due to lack of evidence of the need for high capex and for supplemental funding of the capex. This proceeding also approved a revenue decoupling true up mechanism. Rejection of the capital tracker occurred despite the prior approval by the Massachusetts Department of Public Utilities ("DPU") of capital trackers for Bay State Gas, Boston Gas, and Massachusetts Electric.

The DPU acknowledged that Western Massachusetts Electric's SAIDI and SAIFI performance had deteriorated in recent years even to the point of not meeting DPU standards. However, the Department noted that there were inconsistencies between reliability improvement and the capex levels proposed by the company. The DPU referenced a company estimate that its storm hardening and distribution automation initiatives, which were forecast to cost 16% of the total capex funded through the tracker while providing approximately 76 percent of the SAIDI benefits and 81 percent of the SAIFI benefits. This was contrasted to a company-proposed initiative to proactively replace overhead wire which would cost approximately 22% of the entire budget while providing less than 7 percent of the expected SAIDI and SAIFI benefits. The DPU further criticized the overhead wire initiative as an effort to "replace hundreds of miles of its oldest small gauge wire…, but the record indicates that the

[85] Peoples Gas' analysis included savings in O&M expenses due to reductions in leak repairs, leak surveys, leak rechecks, emergency responses, regulator station inspection and maintenance, vault surveys and maintenance, lost gas, and inside safety inspections.

Company has not yet identified the oldest segments of overhead wire that it will replace, it does not have an accurate method for identifying this wire, nor has it demonstrated that its oldest wire has experienced a disproportionately high rate of failure."[86] The DPU concluded:

> Overall many initiatives within the Company's CRRC proposal, and particularly within the aging infrastructure initiative, are for activities that have received either little or no funding by the Company over the past ten years, which casts doubt on the Company's argument that these activities represent urgent and ongoing priorities…. Although the Company claims that a key objective of the CRRC program is to make additional capital available in order to replace the Company's aging infrastructure, we find that the Company has failed to demonstrate that it is necessary and in the best interests of ratepayers.[87]

<u>Pacific Gas & Electric</u>

PG&E, while operating under an MRP featuring stairstep revenue caps, proposed a six year program called the Cornerstone Improvement Project ("Cornerstone") to improve its reliability performance. The program featured an estimated $2.3 billion in capex and $43 million in O&M spending, leading to a revenue requirement escalation in the plan term of $1 billion. In its assessment of the Cornerstone proposal, the CPUC noted that

> PG&E acknowledges that Cornerstone will not prevent infrastructure failures, but states that, in general, the proposal will allow PG&E to restore service to customers faster and to isolate impacted lines to minimize the customers affected by such failures. While reducing the impacts of outages is a worthwhile goal, as discussed later in this decision, a significantly less costly program from that proposed in Cornerstone can still capture a substantial amount of such benefits. There is no good evidence to indicate what level of overall improved reliability is necessary or appropriate. Without knowing this, there is no way for us to determine that a program as substantial as Cornerstone is necessary."[88]

The CPUC also found that PG&E's current distribution reliability was adequate, projects necessary to maintain adequate reliability were addressed in general rate cases, and PG&E's value of service study though slightly out of date showed that PG&E's customers believed that the company met or exceeded their service expectations was more compelling.[89]

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[86] Massachusetts Department of Public Utilities, January 31, 2011 order in MA D.P.U 10-70, p. 50.
[87] Massachusetts DPU, January 31, 2011 order in MA D.P.U 10-70, p. 50.
[88] CPUC, Decision 10-06-048, p. 16-17.
[89] PG&E had been given an option to update the value of service study and failed to do so.

Nevertheless, some of PG&E's projects were compelling enough for the CPUC to approve specific projects and capital tracker treatment in a properly focused Cornerstone proposal. These projects included distribution automation and circuit connectivity proposals for PG&E's worst 400 circuits, and rural reliability projects that would install 5,000 fuses and 500 reclosers on rural circuits. The CPUC approved a slimmed down Cornerstone proposal made by an intervener that would be able to realize an estimated "68 percent of PG&E's claimed SAIDI benefit and 65% of PG&E's claimed SAIFI benefit for 18 percent of the capital expenditures proposed by PG&E."[90]

Summing Up

To sum up our discussion of these case studies, proposals to track the capital cost of accelerated modernization programs have been rejected or scaled back on several occasions where the evidence of need was insufficient. The need for a specific program is rarely self-evident. Regulators have a legitimate interest in verifying that projects are properly prioritized.

A.5 Qualifications of Witness

This report was prepared by Dr. Mark Newton Lowry of Pacific Economics Group ("PEG") Research LLC, an economic consulting firm that is prominent in the field of incentive regulation plan design. Research on the design of MRPs is a company specialty. The company has played a prominent role in the advance of incentive regulation in Canada. The research team he leads has over 60 person-years of experience in the IR field.

Dr. Lowry is the President of PEG Research. In that capacity he has supervised extensive research on incentive regulation plan design and related empirical issues such as electric utility input price and productivity trends. He has testified on his work in numerous proceedings.

Venues for his testimony on incentive regulation have included Alberta, British Columbia, California, Colorado, Delaware, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maryland, Massachusetts, New Jersey, Oklahoma, Ontario, Oregon, New York, Québec, Vermont, and Washington. His practice is international in scope and has also included projects in Australia, Europe, Japan, and Latin America. Work for diverse clients that have

[90] California Public Utilities Commission, Decision 10-06-048, p. 38-39.

included several regulatory commissions has given Dr. Lowry a reputation for objectivity and dedication to regulatory science.

Before joining PEG Dr. Lowry worked for many years at Christensen Associates in Madison, first as a senior economist and later as a Vice President. The key members of his team have joined him at PEG. Dr. Lowry's career has also included work as an academic economist. He has served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at the École des Hautes Études Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory and statistical methods in industry analysis. He has been a referee for several scholarly journals and has an extensive record of professional publications and public appearances. He holds a doctorate degree in Applied Economics from the University of Wisconsin-Madison.

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