34 King Street East, Suite 600
Toronto, Ontario, M5C 2X8
elenchus.ca

Performance Based Regulation

A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions

Prepared by Elenchus Research Associates, Inc.

January 2015

Page Intentionally Blank

Table of Contents

Appendices

Page Intentionally Blank

EXECUTIVE SUMMARY

The Régie de l'énergie (the Régie) will hold a public hearing to establish a performance based regulation (PBR) regime for Hydro Quebec's distribution and transmission divisions. In anticipation of this proceeding, the Régie retained Elenchus Research Associates Inc. (Elenchus) to prepare this report to provide an overview of the international experience with PBR.

The literature on economic regulation indicates that the original goal of PBR and other forms of incentive regulation (IR) was to embed in the regulatory methodology explicit incentives that would motivate utilities to become more productive. The resulting productivity improvements were expected to facilitate lower costs, or at least reduced cost increases, while maintaining service quality levels that are responsive to consumer expectations. In practice, regulators have found it appropriate to identify additional objectives that include specific service quality targets and other policy objectives ranging from investing in technological innovation to achieving conservation targets and increasing renewable energy in the supply mix.

One observation that readily emerges from our review of the international experience with PBR is that there is no single "best practice" in terms of the mechanics that are used to provide the intended incentives. However, there does appear to be "best practices" in terms of the approach used to design a regime that is appropriate within any particular jurisdictions

The first step in designing an effective PBR regime is to clearly define its objectives. Having done that, it is necessary to understand the behaviour, goals and shortcomings of the regulated utility or utilities as well as the structure of the industry. A regime that is appropriate in a jurisdiction that regulates a large numbers of similar utilities may not be transferable to a jurisdiction, such as Quebec, where the PBR regime will be used for a single service provider. Similarly, a regime that works well with shareholder-owned utilities may be less effective if used to regulate a crown corporation.

Finally, it will be important to accept that any PBR regime will need to be monitored on an ongoing basis so that concerns can be identified and the regime can be evolved and improved in order to adapt to new policies and challenges as they arise.

Six specific jurisdictions that utilize PBR are reviewed in this report. Three of these jurisdictions use PBR to set rates for electricity distributors: Ontario, Alberta, and New York (which has used PBR to set rates for Consolidated Edison for several decades). The other three included in the review use PBR to set rates for electricity transmission companies: United Kingdom, Australia and Norway. These case studies are used to illustrate a number of common features of PBR as implemented internationally.

The initial PBR regimes in the jurisdictions included in this review all had multi-year terms with rates in the initial year of each term being set using a traditional cost of service approach. For the balance of the term, these regimes used an escalator (CPI-X) that reflects inflation (CPI) and a productivity target (X) to adjust annually either rates (rate cap) or the allowed revenues (revenue cap). Rate caps are generally used for distribution utilities in order to stabilize costs on a per unit basis since costs tend to increase with number of customers and/or volumetric throughput. Revenue caps are commonly used for transmission utilities since costs tend to be relatively insensitive to year-over-year changes in throughput; however, separate adjustments are typically allowed for the occasional major capital investments that are required to maintain facilities and increase the capacity of transmission companies.

When used for either price or revenue caps, the basic CPI-X mechanisms have been enhanced with additional features that recognize the reality that a simple formula cannot accommodate all cost pressures faced by an electric utility. The additional features include: cost items that are passed through outside the formula (Y factors), costs associated with extraordinary and unanticipated events that are outside the control of the utility (Z factors), earning sharing mechanisms, a mechanism for exiting the PBR regime if returns problems arise (off-ramp), and service quality reporting mechanisms.

In general, PBR regimes have evolved from relatively simple rate control mechanisms to more complicated regimes that recognize concerns other than reducing costs, such as improving service standards, implementing government policies related to energy conservation, increasing the role of renewable generation, consumer responsiveness, etc. A few regimes have evolved to outcomes-based regimes that seek to address these broader issues with a more comprehensive and more flexible approach.

The Ontario Energy Board has developed a regulatory regime for electricity distributors that reflects the unique features of Ontario's industry: there are still close to 70 OEB regulated distributors that had no experience prior to 2006 in prepare comprehensive rate applications. Many also face growing capital requirements. The regime has been complicated with the evolving government policy framework that has included the introduction of unbundled electricity services, an increasing focus on conservation, and the requirement to connect renewable generation, among other policy goals. The Ontario PBR regime has also evolved as a result of improvements in the data available to the OEB and the growing experience of stakeholders with formal regulatory tools.

In Alberta, PBR was first introduced in 2009 when Formula-Based Ratemaking ("FBR") was approved by the Alberta Utilities Commission for ENMAX. A generic version of this ratemaking methodology was adopted for the other Alberta distribution utilities in 2013. The Alberta design included a capital tracker mechanism that is used to pass through capital costs outside of the CPI-X formula. Capital tracker applications require a detailed understanding and testing of individual utilities' proposals. These reviews can involve significant regulatory effort on an annual basis. Overall the AUC clearly considered the benefits of including this feature to outweigh the costs although it sacrifices the benefit of streamlining the regulatory process that many regulators consider to be an important reason for adopting PBR.

The New York Public Service Commission ("NYPSC") has adopted multi-year rate plans for Consolidated Edison ("Con Edison"), the largest utility in New York. While multi-year regimes generally provide less effective incentives for improving productivity than CPI-X regimes, they do provide greater opportunities for a utility to benefit from efficiency improvements than annual cost of service reviews. Multi-year reviews also tend to reduce regulatory costs. Con Edison's rates are now usually determined for a three-year period which gives the company significant flexibility to change the way it allocates resources during the rate term of the plan. This approach involves more on-going cost scrutiny than CPI-X regimes, which in some circumstance may be considered essential. The NYPSC's reviews of the company focus on the utility's performance based on service objectives defined by the regulator as well as its actual costs as compared to the approved forecast costs for the period under review.

In the United Kingdom, the price control regime initially adopted by OFGEM for both distributors and transmitters was a form of price cap. For transmitters the average revenue per MW was capped, with annual adjustments based on an RPI-X formula. The initial rate for each price control cycle was established based on a review of each utility's costs. The price control mechanism for transmitters was changed from a price cap to a revenue cap in 1995. The intention was to remove the incentive for the utilities to increase their volume throughput in order to increase profitability.

The key innovation of the latest PBR regime implemented by OFGEM, known as RIIO, is its focus on outputs rather than inputs. This approach aligns the regulatory process with the expectations of customers who care more about performance than how that performance is achieved. The regime seeks to mimic competitive markets in making service providers responsive to their customers. The RIIO model is built around three types of incentives:

- Output incentives: The allowed revenues of the network companies are adjusted each year based on their performance relative to approved performance targets based on business plans that they submit to OFGEM.
- Efficiency Incentives: The model separately rewards the utilities for realizing efficiency gains by allowing them to retain the resulting increases in net income.
- Innovation Incentives: Companies bid for funding through a competitive process.

There is also an Information Quality Incentive (IQI) which rewards companies for submitting accurate expenditure forecasts.

In Australia the National Electricity Market ("NEM") was created in 1998. The Australian Energy Regulator ("AER") initially relied on the CPI-X model of rate control; however, in 2013, it undertook a Better Regulation program to enhance the approach to be used in regulating electricity networks. The Better Regulation program brought together a number of reforms, including new annual reporting on efficiencies, new tools to assess business expenditure forecasts, stronger incentives, a better way to determine the return on investment and a better consumer engagement framework.

The Australian revenue cap incentive regime for transmitters is essentially a five-year cost of service regime that sets a smoothed revenue trajectory over the five-year term based on projected costs for the period. The costs used to establish the five-year revenue requirement become the target cost for the PBR regime. The transmitter has an incentive to reduce costs while meeting its established service quality standards since it is able to retain a share of the savings that are realized. The sharing mechanism serves as an alternative to using a stretch target as a means of flowing a share of the benefit of any enhanced productivity gains through to consumers.

Rates for electric distribution and transmission utilities in Norway have been set using a performance based regulation regime since 1997. The approach adopted by the Norwegian regulator, the Norwegian Water Resource and Energy Directorate (“NVE”) was a revenue cap based on benchmarking. This regime is now in its fourth term.

All of these regimes have built on the initial insights developed in the literature in the preceding decades that explicit efficiency incentive could be introduced into traditional cost of service regulation by means of four innovations.

First, incentive regimes explicitly recognize that utilities should be able to earn a premium over their standard allowed return on equity if they achieve performance targets established by the regulator. Although the initial incentives focused on cost reductions, the incentives have been expanded so that they explicitly apply to many other performance targets.

Second, since there are limited opportunities to realize savings within a single year, effective incentive regimes allow utilities to pursue productivity gains and retain the benefits of those efforts over an extended period, sometimes carrying over from one term to the next.

Third, since costs tend to increase over time due to inflationary pressures, cost benchmarks are usually adjusted by some measure of inflation.

Fourth, since some degree of productivity improvement is expected, except in extraordinary circumstances, PBR regimes include a productivity factor. The productivity factor also serves as a mechanism for sharing of the anticipated efficiency gains between the company (higher profit) and consumers (lower rates).

Over time, the initial incentive regimes tended to become more complicated as regulators recognized the need to provide incentives for behaviours other than cost reductions. In particular, it was quickly recognised that the easiest way for utilities to cut costs and increase profit was to reduce maintenance and defer capital expenditures. The resulting decline in reliability and other service standards was not always consistent with the goal of enhancing productivity. Consequently, a standard feature of the evolution of PBR regimes was the inclusion of quality of service standards.

Many regimes have also evolved and become more complex because of the need to incorporate additional performance standards related to specific policy objectives such as energy conservation and the accommodation of renewable generation.

As a result of this increasing complexity, the latest evolution of the UK, Australian and Ontario regimes has been to adopt comprehensive outcomes-based regimes. These PBR regimes emphasize measuring success in terms of defined performance outcomes. They require the utilities to demonstrate that they are developing business plans based on consumer engagement and comprehensive planning.

The next challenge for regulators may be accommodating rate design changes within a PBR framework. The electricity industry is changing in ways that may make it desirable to adopt innovative rate designs in order to protect the utilities' revenue base and provide price signals that are efficient. For example, as new technologies make self-generation more economic, the risk that customers will begin to reduce or eliminate their reliance on the grid is an emerging concern. As this issue becomes more pressing, there may be a need for utilities to develop service and pricing strategies that respond to the competitive threat; however, if regulators allow utilities some discretion introduce new services, modify their rate designs and rebalance rates among customer classes and services, they will also have to provide the required oversight to avoid the flexibility resulting in anti-competitive or discriminatory practices.

1. INTRODUCTION

The Régie de l'énergie (the Régie) will hold a public hearing to establish a performance based regulation (PBR) regime for Hydro Quebec's distribution and transmission divisions. The Régie is undertaking this initiative in response to a recent legislative change. The *Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012* (the Law)[1] requires that the Régie establish performance based regulation (PBR) for Hydro Quebec. In a recent proceeding, Hydro Quebec proposed an earnings sharing mechanism as a means of introducing PBR.[2] The Régie determined that the proposal did not meet the legislative requirements.[3]

Section 48.1 of the Law identifies performance, efficiency and process objectives for the Régie's PBR regime:

> *48.1. The Régie shall establish a performance-based regulation to ensure efficiency gains by the electric power distributor and the electric power carrier.*
>
> *The regulation must pursue the following objectives:*
>
> *(1) ongoing improvement in performance and service quality;*
>
> *(2) cost reduction that is beneficial to both consumers and the distributor or carrier; and*
>
> *(3) streamlining of the process by which the Régie fixes or modifies the rates the electric power carrier and the electric power distributor charge consumers or a class of consumers.*

In anticipation of this proceeding, the Régie retained Elenchus Research Associates Inc. (Elenchus) to prepare a reference document that identifies and compares the principal parameters of PBR regimes that could be applied to Hydro Québec's distribution and transmission divisions.

The term performance based regulation is not used consistently in the literature or by regulators internationally. In its common usage, PBR is closely related to the more

---

1 Bill 25, *Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012,* 1st session, 40th legislature, Quebec, 2013 (sanctioned June 14th 2013), L.Q., 2013, c.16

2 R 3842 2013

3 Decision D 2014 033

general type of regulation termed “incentive regulation”, or “IR”. Often these terms are used interchangeably. Price cap regulation and revenue cap regulation are specific types of incentive regulation or PBR that have been implemented by regulators in many jurisdictions. This report reviews regulatory frameworks which are known by each of these labels since all variations are used by regulators to achieve objectives that are closely related to objectives identified in section 48.1 of the Law.

1.1 STRUCTURE OF THE REPORT

This report consists of eight additional sections. Sections 2 and 3 provide overviews of the theory of regulation and the evolution of PBR as implemented by regulators over the past few decades.

Sections 4 through 6 examine three jurisdictions with PBR regimes that apply primarily to electricity distributors:

- the Ontario Energy Board’s incentive regulation regime that is currently transitioning into its fourth generation of IR;
- the Alberta Utilities Commission regime that is currently being used for all electricity distributors in Alberta; and
- the New York Public Services Commission regime applied to Consolidated Edison that has evolved over more than 20 years.

Sections 7 through 9 examine three jurisdictions with PBR regimes that are specifically tailored to apply to electricity transmitters:

- the regime developed by the Office of Gas and Electricity Markets (“OFGEM”) which has evolved significantly over the past 25 years;
- the Australian Energy Regulator’s regime that applies to TransGrid which also has evolved through several generations; and
- the incentive regime that the Norwegian Water Resource and Energy Directorate introduced in 1997 for Statnett, its transmission operator, which has also evolved over the years.

Each of the latter three jurisdictions has also adopted a PBR regime for electricity distributors that is similar to the regime that is used for transmitters. While the focus of sections 7 through 9 is on the PBR regimes that are used for transmitters, these sections include some discussion of the regimes used for distributors. The tailoring of PBR to apply specifically to distributors and transmitters by these regulators is relevant to the issues being addressed by the Régie which is examining regulatory models that could be used for both the Transmission and Distribution divisions of Hydro Quebec.

Each of the six sections examining specific IR/PBR regimes contains an overview of the features of the regime and a summary of the strengths and weaknesses of each regulatory regime that explains how it has evolved. Key observations that appear to provide useful context for the process that will be considering PBR regimes for Hydro Quebec's transmission and distribution divisions are included in these six sections.

The tenth and final section provides a brief summary of the generic observations from the preceding sections of the report.

Included in the appendices are summary tables that compare the features of the six regimes examined as well as references for further reading with respect to each of the main sections of the report. The appendices also include additional detail related to how the various regimes operate. It should be noted, however, that the mechanics of each regime are complex, and the changes from period to period are often extensive. The main body of the report is intended to provide only a high level overview of the approach taken by each jurisdiction. While the appendices include more detail on the mechanics of each regime, the descriptions are not intended to be comprehensive. A full appreciation of the implementation details for any of these regimes would require reading at least the primary references provided in the appendices.

2. OVERVIEW OF THE THEORY OF PBR

Although government regulation to establish rates that are in the "public interest" can be traced back several centuries,[4] the roots of modern forms of rate regulation based on a formalized assessment of the cost of service date most clearly from the early 20th century. The shortcomings of relying on a traditional review of a utility's costs as the basis for setting rates have long been recognized in the academic literature.[5] Nevertheless, until the 1990's traditional cost of service rate regulation was broadly accepted as the best protection against monopoly pricing for the goods and services produced by industries deemed to be public utilities.[6] The industries that have been viewed as natural monopolies where rate regulation is in the public interest include the transmission and distribution of electricity.

As a consequence, regulators of industries that were considered to be natural monopolies were generally satisfied to focus their efforts on seeking better ways to determine the level of costs that were prudent and necessary as a basis for setting rates.[7] The explicit consideration of regulatory incentives rarely entered into the decisions of regulators although the academic literature had extensively explored the now accepted view that any form of regulation embeds incentives and disincentives whether intentionally or not. The literature argues that regulatory regimes should recognize and exploit incentives through performance based regulation.

Alfred Kahn, who is sometimes referred to as the "Father of Airline Deregulation"[8], was an early implementer of regulatory change. His influential two volume book (1970-71), contains a chapter entitled "Incentives and Distortions" in which he provides an

---

4 Goodman makes reference to rate regulation in England dating to the 14th and 15th century with an early treatise on the subject being Lord Chief Justice Hale, *De Portibus Maris* written in about 1670.

5 There is an extensive academic literature on performance based regulation. See the references for further reading in Appendix 10

6 For example, the seminal work of Bonbright (1961) is explicitly based on the principle rates for public utility services should be based on the "cost principle. See Bonbright (1961) page 24.

7 The trend toward deregulation of industries where price competition was feasible, such as railways, trucking, and airlines preceded incentive regulation. The telecommunications industry was also deregulated, but only after technological developments enabled effective competition.

8 As noted in: Wikipedia (Alfred E. Kahn).

extensive list of ways in which regulatory incentives result in inefficient investment "might be reflected".[9] His key points include the following concerns.

- Many public utility companies adopt pricing regimes that increase peak demand, which justifies increased capital investment.
- They often maintain excess standby capacity, reserve margins and high standards of reliability and uninterruptibility of service, which require increased capital investment.
- They often resist the introduction of capital-saving technologies.

He also indicates that regulators have limited ability to blunt these distortions under traditional cost of service regulation and that incentives can be more effective than oversight in minimizing these distortions.

> *There just is no easy way of eradicating these possible distortions of incentive, within the regulatory context; all the commission can do is to supervise, prod, and subject proposed investments, promotional prices and the like to economic tests. …*
>
> *But, by the same token, these dangers can be drastically attenuated or eliminated to the extent that regulated companies can be exposed to the same incentives and pressures as apply outside of the regulatory context – <u>the incentive of higher or lower profits depending on individual performance, and the pressures of competition</u>.*[10] (emphasis added)

As this paper's review of selected the PBR regimes demonstrates, the concept of the incentives described by Kahn is at the heart of PBR regimes that have been implemented in the last quarter century.

Kahn's subsequent discussion of incentive plans observes that the plans proposed prior to 1970 had both strength and weaknesses. He does not advance a proposal for performance based regulation as we know it today. He does however lay out a conceptual framework that remains useful today by identifying the main relevant aspects of performance:

---

[9] Kahn, Vol. II, pages 50-54.

[10] Kahn, Vol. II, page 56.

1. *Efficiency – the level of costs.*
2. *The relationship of prices individually and collectively to cost – to marginal cost in the short run, to average cost in the long run.*
3. *Improvements in efficiency over time and the passing on of the benefits to consumer, as reflected in cost and price trends.*
4. *The quality of service.*
5. *Service improvement and innovation over time.*[11]

These criteria remain central to the development of performance based regulation regimes today. However, Kahn focussed on the role of competition rather than innovations in regulatory methodology as the means to address what he viewed as the inherent limitations of regulation while at the same time recognizing that competition was not always practical. As he stated:

> *Competition is far more powerful than regulation in forcing businesses to explore the slope of their cost functions and elasticity of their demands, and to push down costs, if they are to prosper. In those situations in which competition is feasible, regulatory commissions clearly should welcome it rather than rush to restrict it.*[12]

Given this view, it is not surprising that more of Kahn's career was devoted to deregulating industries than to designing PBR regimes.

As discussed in the next section, regulators began adopting various forms of incentive and performance based regulation in the 1980's and 1990's. Assessments of these regimes began to appear in the literature by the mid-1990's. For example, Thomas P. Lyon's paper entitled "*Incentive Regulation in Theory and Practice*"[13] provided an overview of incentive regulation regimes including price caps, sliding-scale regulation and yardstick competition, optional tariffs and hybrid mechanisms. Lyon noted that a 1990 survey of U.S. jurisdictions found that a very wide variety of regimes had been implemented across the United States.[14]

---

[11] Kahn, Vol. II, page 95.

[12] Kahn, Vol. II, page 112.

[13] See Crew (1994) pages 1-26.

[14] Ibid., page 17.

The concluding comments of Lyon's paper open with the observation that regulatory practice has not only been adopting the insights of the preceding theoretical analysis, but the real-world experience of regulators was informing and advancing the academic literature.

> *The interest in and implementation of IR schemes proceeds apace, providing a fascinating meeting ground between theory and practice; to date, the twain have drawn closer but not yet met, As this survey attempted to show, there is a variety of approaches to IR which have yet to be fully drawn together in an integrated theory. Nevertheless, the basic principles and issues involved are becoming clearer, providing some general guidance for regulatory design.*[15]

A decade later, Paul L. Joskow prepared a survey that updated the status of IR in the context of electricity distribution and transmission networks.[16] This paper contains observations that are as relevant now as they were a decade ago. His introduction highlights the many practical challenges that need to be addressed when attempting to implement the concepts of IR/PBR within a practical regulatory regime that has multiple objectives, imperfect data and other confounding factors. He notes that:

> *As I will discuss, the implementation of incentive regulation concepts is more complex and more challenging than may first meet the eye. Even apparently simple mechanisms like price caps (e.g. so-called "RPI – X" regulation) are fairly complicated to implement in practice, are often imbedded in a more extensive portfolio of incentive regulation schemes, and depart in potentially important ways from the assumptions upon which related theoretical analyses have been based. Moreover, the sound implementation of incentive regulation mechanisms depends in part on information gathering, auditing, and accounting institutions that are commonly associated with traditional cost of service or rate of return regulation. These institutions are especially important for developing sound approaches to the treatment of capital expenditures, to develop benchmarks for operating costs, to implement resets ("ratchets") of prices, to take service quality attributes into account, and to deter gaming of incentive regulation mechanisms that have mechanisms for resetting prices or price adjustment formulas of one type or another over time.*

---

[15] Ibid., page 22.

[16] Joskow, Paul L. (2006) "Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks" MIT, prepared for the National Bureau of Economic Research Conference on Economic Regulation, September 9-10, 2005.

The review of six jurisdictions in the sections that follow reinforces this view. As regulators gain more experience with PBR, additional challenges come to light and the performance based regimes that are in place evolve and become more complex.

Joskow's paper identifies five practical questions that he suggests regulators should address in order to "apply the theory in practice in the design of actual incentive regulation mechanisms."

> a. *Where does the regulator's information about the firm's actual costs and the distribution of cost opportunities come from?*
>
> b. *Should the regulator offer the regulated firm a menu of contracts or a specific contract with a single set of values for a and b [cost and quality]?*
>
> c. *What benchmarks are to be used to arrive at starting values for the regulated firm's costs, revenues, and other performance indicia and how are these benchmarks adjusted over time?*
>
> d. *What should be the power of the incentive scheme?*
>
> e. *Should the incentive mechanism be comprehensive or "partial"?*[17]

Regulators are continually finding better ways to respond to these issues.

The most recent textbook on regulation released by Public Utilities Reports, Inc. is the latest in the long line of publications on the topic of regulatory theory and practice. It contains a chapter on alternative regulatory structures that includes a section devoted to performance based regulation. While the topic is not addressed extensively in this volume, it highlights the primary design features used by regulators and the rationale for moving to these regimes as well as noting the primary drawbacks.

> *There clearly are benefits to formula-based price (or revenue) regulations, but setting initial values and parameters and evaluating and making changes to the process over time, are still significant challenges that are often subject to political meddling. The need for good information is not lessened, though it might be argued that the relevant information is needed less frequently.*[18]

---

[17] Joskow (2006) pp. 15-18. His discussion of these questions provides interesting insights into the challenges to be addressed. The paper concludes with a Discussion section that set out ten interesting observations for discussion at the conference.

[18] Lesser and Giacchino, p. 88.

It is clear that neither the literature nor regulatory practice has identified a foolproof formula for designing an effective performance based regulation regime. On the contrary, experience to date suggests that there currently is not, and probably never will be, a clearly defined "best practice" for PBR. Rather it will be necessary to recognize the unique economic and infrastructure characteristics of each utility and each jurisdiction in order to determine how to implement the guiding principles to performance based, or incentive, regulation that will be effective in achieving the specific objectives that the regulator is pursuing.

2.1 KEY OBSERVATIONS

There is an extensive academic literature that explores the strengths and weaknesses of both traditional cost of service and contemporary IR/PBR regulation. This literature highlights the conceptual advantages of incentive based methodologies as well as the practical challenges of implementing IR/PBR regimes. Nevertheless, there appears to be broad acceptance that while IR/PBR regimes have yet to be perfected, they can be superior to traditional COS regulation as a means of streamlining the regulatory process and better aligning the interests of utilities with their customers.

In general, the goal of IR/PBR is to embed explicit incentives into the regulatory regime that motivate utilities to become more productive so that costs will be reduced while service quality will be responsive to consumer expectations. The ideal is that regulated utilities would be as focused on operational efficiency and customer satisfaction as firms operating successfully in a competitive environment.

It is recognized, however, that it can be challenging to design and implement an IR/PBR regime that meets these goals. For example, the information and data needed to determine the required parameters will never be perfect; hence, it is necessary to balance the costs and benefits of greater "perfection" in the methodology.

More generally, as the Joskow paper cited above implies, the first step to designing an effective PBR regime is to clearly define its objectives. Having done that, it is necessary to understand clearly the behaviour, goals and shortcomings of the regulated utility and local industry so that the regulator can design a regime that is appropriate in the local circumstances. Finally, recognizing the challenges faced in designing an effective PBR regime, it will be important to accept that any PBR regime will need to be monitored on an ongoing basis so that concerns can be identified and the regime can be enhanced when necessary in order to adapt to new challenges as they arise.

3. OVERVIEW OF THE EVOLUTION OF PBR [19]

The purpose of this section is to complement the preceding discussion of the theory of PBR in providing a high level overview of the drivers behind the evolution of rate regulation from cost of service to IR/PBR. This section provides the broader context before examining the experience with PBR in the six selected jurisdictions.

3.1 TRADITIONAL COST OF SERVICE RATE REGULATION

Traditionally, utilities have been rate regulated using what is called a "cost of service" approach.[20] The regulator assesses the costs of providing the utility service (sometimes on the basis of one historical year, but often on the basis of one forecast year) and sets rates that are sufficient to recover those costs, including a fair rate of return on the capital invested.[21] The focus is on whether the forecast costs are reasonable and whether past capital expenditures were prudent.

Depending upon how much time elapses between rate cases, a utility may have an incentive to reduce costs relative to the forecast in order to increase its achieved return. The term "regulatory lag" refers to the time between rate cases in which the utility has an incentive to increase its efficiency and reap benefits for the shareholder.

The cost of service approach has a number of shortcomings that are widely recognized in the literature, as discussed in the preceding section, as well as several practical concerns that have been identified by regulators.

First, the regulator is at a disadvantage when trying to determine whether expenditures are really needed. The utility has access to far more information than the regulator. The objective of regulation is not to micro-manage the utility or to take operational decision-making authority from management; the objective is to set the parameters within which

---

19 See Appendix 10 for suggested further reading.

20 This regulatory method is also often referred to as rate-base rate-of-return regulation when applied to shareholder owned utilities. Approved OM&A costs are passed-through on a dollar-for dollar basis, but capital costs are the basis for deriving a rate base to which an allowed cost of capital is applied.

21 In the case of crown corporations, rates are set at a level that is consistent with specific financial criteria, such as a target debt ratio, rather than at the level consistent with an allowed rate of return.

the utility will perform. However, the result is a tendency to require extensive information from the utility to demonstrate that the forecast expenditures are justified.

Second, the time between rate applications may be uncertain since rate proceeding can generally be initiated by the utility or the regulator. The utility therefore cannot be sure how long it will have to recover the costs and benefits of efficiency improvements. This uncertainty can be a disincentive for making investments that are expected to increase costs in the short run (i.e., prior to the next COS proceeding) but generate cost savings in later years (after the next COS proceeding). This scenario can result in the costs being borne by shareholders while the benefits are captured for customers.

A related factor is the pressure on regulators to initiate a cost of service proceeding for any utility which is perceived to be earning “excess” returns. Utilities may take the view that there is little benefit to shareholders from aggressively pursuing productivity gains, especially if the realization of those gains is uncertain. Initiatives that are successful in reducing costs may result in lower rates, and initiatives that fail to achieve the intended benefits may be deemed imprudent and the costs may not be recoverable.

Third, the utility will have an incentive to file annual rate applications if input costs are generally rising or if the system is expanding. If the utility’s level of investment and spending is higher than the amount reflected in its current rates, and if it can convince the regulator that the increased expenditures are reasonable, then the incentive is to return on an annual basis for new rates. If there are annual proceedings, then new investments begin to earn a return as soon as possible and the risk that capital expenditures will later be found imprudent and hence excluded from rates is lower.

Given these considerations, the tendency under cost of service regulation is toward annual or bi-annual rate proceedings. The result is that utilities generally will have little incentive to become more efficient. Instead, the incentive is to over-invest in or “gold-plate” infrastructure, assuming the utility finds the allowed return on investment attractive. Annual or bi-annual rate proceedings are also very resource intensive for the utility and the regulator – as soon as one proceeding has been completed preparation for the next one begins.

The shortcomings of cost of service regulation in terms of the absence of embedded incentives to reward the utility for pursuing efficiency improvements have been recognized for many years. In fact, different forms of performance-based or incentive regulation have existed for utilities since the early 20th century. The importance of shifting the emphasis from a detailed examination of costs to a greater emphasis on providing efficiency incentives has long been recognized, as discussed in the preceding section. The fact that the interests of consumers relate more to the total price than to the level of profit earned by the utility has also long been recognized. The following appeared in a book published in 1976:

> *In a sense, regulatory agencies have become obsessed by the spectre of excess profits. It is past time that they transfer their obsession to costs and to the technical efficiency of the regulated firm. Posner puts it aptly. "Most consumers would rather pay $1 for a long-distance call, 20 cents of which represented a monopoly profit….than $1.10, all of which was cost."*[22]

If the price of greater efficiency is that the utility makes higher profits, then it is logical that this trade-off would be accepted provided that the efficiency gains are shared, with consumers paying less and shareholders earning more.

One solution to the shortcomings of cost of service regulation might be to embed higher expectations for efficiency in the annual cost of service rates. Conceptually, this approach provides the greatest benefit to consumers since the efficiency gains need not be shared with the shareholders. However, it is hard to establish the most efficient level of costs, particularly on an annual or bi-annual basis for an individual utility, and often it takes more than one year to implement efficiency improvements and see the benefits. Three solutions present themselves:

1. Establish a system whereby it is in the utility's interest to be efficient.
2. Establish a system that facilitates the comparison of utilities – that is, establish a form of "competition" in service efficiency.
3. Separate rates from costs by using external inflation and productivity measures.

[22] W. Stanbury, *The Consumer Interest and the Regulated Industries: Diagnosis and Prescription*, in Transportation Policy: Regulation, Competition and the Public Interest, Ruppenthal and Stanbury eds., University of British Columbia, 1976, p. 131.

These are three of the key principles underpinning incentive and performance-based regulation.

3.2 THE EMERGENCE OF PRICE AND REVENUE CAP REGULATION

Price control regulation is a particular form of incentive regulation developed by Stephen Littlechild, a United Kingdom Treasury economist and the first UK electricity regulator. As discussed in section 7, below, this regime was implemented in the UK in 1990. The initial incentive regime adjusted rates annually based on a formula (the Retail Price Index minus the expected or target efficiency savings, “RPI-X”). This approach is more commonly referred to as “CPI-X” in North America where CPI is the Consumer Price Index, or simply I-X where I represents inflation. The price cap regime was intended to provide an incentive to pursue enhanced productivity gains since any savings above the predicted efficiency savings (X) is retained by the utility until rates are rebased through a periodic cost of service review. It was also easily understood by consumers to mean that prices would increase more slowly than inflation. The framework was adopted throughout the gas and electricity systems in Great Britain, and was part of a broader policy framework which included market liberalization and privatization.

Variations of the CPI-X approach to incentive regulation have been widely adopted by regulators over the past quarter century. For example, another form of price control, referred to as revenue cap regulation also uses CPI-X as the adjustment factor, but in this case it is used to adjust the allowed revenues annually to reflect the impact of inflation and deemed productivity on costs. Capping annual revenues, rather than rates is appropriate when the utility is mature and increasing or declining throughput does not have a significant impact on the utility’s infrastructure, other than to increase (or decrease) utilization of the existing infrastructure. Furthermore, as the case studies discussed in the following sections illustrate, where capital investments are lumpy and do not relate closely to overall system throughput, the CPI-X escalator can be used to limit total revenue associated with the base capital, while allowing separate adjustments for the lumpy capital additions.

While price control regulation was quickly recognized as an effective way to address the perceived failure of traditional cost of service regulation to induce utilities to operate efficiently, regulators also recognized this conceptually elegant rate setting methodology was not a panacea. In particular, even in the early days of this PBR regime, some regulators found it challenging both to identify an inflation index that reflected the inflation pressures faced by the utilities and to establish an efficiency standard that was an accurate proxy for competitive pressures. While getting the values "right" is not critical in the case of a highly inefficient utility, the more efficient a utility is (or becomes as it responds to price cap incentives that have been in place for many years), the more critical it is to set the values appropriately.

To address these concerns, regulators have developed a number of variations of the basic price control designs. For example, the cost pressures on a utility may not correspond to the inflation trend in consumer prices, so more industry-specific inflation factors, or multiple factors, have been used. Regulators have also used different methods to establish an appropriate productivity index, with the general goal being to push the utility to pursue productivity gains aggressively while not setting a productivity target that compromises the financial integrity of the utility by being excessive.

In addition to these technical concerns, regulators quickly recognized that the incentive inherent in a pure price control regime can be to reduce costs, as distinct from increasing productivity. For example, cost reductions can be achieved very easily in the short run by deferring efficient expenditures (e.g., on-going maintenance), resulting in higher costs in the long run. Cost reductions can also be achieved by reducing service standards. As a result, many regulators enhanced their PBR regimes by adopting mandatory quality of service standards, sometimes with associated financial penalties.

3.3 THE DEVELOPMENT OF IR/PBR

Comprehensive IR/PBR as we know it today has developed largely since the 1990's. The principles that most commonly guide the development of IR/PBR regimes can be expressed as follows:

- The base revenue requirement and base rates are set using a cost of service review.

- An automatic revenue or rate adjustment mechanism is used each year. The adjustment incorporates inflation and productivity (CPI-X) in order to recognize cost pressures and to ensure that a share of the benefits of greater efficiency flow through to customers during the term of the plan.
- Productivity targets are set using the utility's own performance, comparative benchmarks, the regulator's judgment, or a combination of these methods.
- An extended period between rebasing applications (i.e., cost of service reviews) is set in advance to provide an opportunity for the utility to realize results from productivity initiatives before its next rebasing. During the term of the plan the utility retains the benefits of efficiency improvements over and above the productivity factor described previously. The productivity gains are generally incorporated into the rates at the next rebasing although there may also be a "carry-over" mechanism that allows shareholders to benefit equally from productivity initiatives whether they are undertaken early or late within the term of the PBR plan.
- Service quality standards are set to ensure that profitability is not improved simply by reducing service. The standards may be accompanied by specific penalties for under-performance and/or incentives for superior performance.
- Reporting requirements are established to ensure ongoing data availability for evaluating productivity, benchmarking and assessing service performance.

The desired outcomes of IR/PBR include lower rates (or lower rate increases) compared to cost of service, improved service and a more rational allocation of risks and rewards. This is accomplished by aligning the interests of customers and shareholders – both benefit by sharing efficiency gains. IR/PBR is also generally held to allow utilities to be more innovative, responsive to customers, and more flexible in terms of their operations.[23]

Furthermore, IR/PBR can reduce the risk of inappropriate deferral of capital investments if the capital plan is reviewed during the IR/PBR proceeding and the rates during the

---

[23] *Performance-Based Regulation for Distribution Utilities*, The Regulatory Assistance Project (NARUC), December 2000.

IR/PBR term are set to recover those investment costs. In cost of service regimes, capital expenditures are generally only considered for a single forecast year. [24,25]

While the underlying principles of PBR are constant, the specific objectives/criteria may evolve over time as circumstances change. When setting an IR/PBR framework, the regulator typically initiates the policy process by considering the objectives or criteria that will be used for designing the PBR regime. This facilitates the evaluation of alternatives and the post-implementation evaluation of the selected approach.[26]

Although PBR is typically adopted to provide an incentive for utilities to become more efficient, each jurisdiction typically has additional objectives or drivers that are unique to its circumstances. Hence, each PBR regime is best understood in the context not only of the general principles but also in terms of its own guiding objectives. Even when objectives are set by legislation, the regulator often develops a more detailed list of objectives. The Regulatory Assistance Project (associated with NARUC) has identified a useful list of objectives for regulators to consider in developing a PBR regime:

- Cutting costs
- Innovating
- Improving customer service and satisfaction
- Reallocating risks
- Encouraging investment (perhaps in specific areas)
- Environmental Improvement
- Other goals (e.g. simplified process)[27]

Other potential objectives suggested in the literature or by regulators include:

- Public acceptability

---

24 L. Kaufmann, *Incentive Regulation for North American Electric Utilities*, in **Energy Law and Policy**, G. Kaiser and B. Heggie, editors, 2011.

25 An interesting exception to this generalization is the modified regime recently introduced in New Brunswick which includes a legislative requirement for NB Power to file Ten Year Plans and for the regulator to take the long term plan and the company's debt ratio into account when setting rates.

26 K. Costello, *Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas*, The National Regulatory Research Institute, September 2007.

27 *Performance-Based Regulation for Distribution Utilities*, The Regulatory Assistance Project (NARUC), November 2000.

- Rate stability
- Energy efficiency improvements
- Ratepayer benefits
- Shareholder rewards for superior performance
- Rigorous planning

In Ontario, the OEB originally implemented PBR for the natural gas utilities without pre-established objectives or criteria. This resulted in serious stakeholder dissatisfaction.[28] The OEB subsequently established the following criteria for natural gas PBR after consultation with stakeholders but in advance of the company-specific applications:

> - *establish incentives for sustainable efficiency improvements that benefit both customers and shareholders*
> - *ensure appropriate quality of service for customers*
> - *create an environment that is conducive to investment, to the benefit of both customers and shareholders*
>
> *The Board believes that a ratemaking framework that meets these criteria will ensure that the statutory objectives of consumer protection, infrastructure development and financial viability will be met, and that rates will be just and reasonable.*[29]

The OEB also identified six factors it would consider in reviewing the PBR plans:

- whether the plan is targeted or comprehensive;
- the sharing of benefits/earnings between ratepayers and shareholders;
- the complexity of the rate adjustment mechanism;
- the term of the plan;
- transparency of information during the term of the plan; and

[28] The OEB observed in its report on natural gas IR/PBR: “Stakeholders perceived a lack of direction from the Board and exhibited a degree of scepticism in the trial PBR process. The submissions indicated that greater understanding and consensus on PBR would likely emerge if the Board clearly articulated its views about the purpose, application and most appropriate design of PBR plans.” (page 17)

[29] Ontario Energy Board, *Natural Gas Regulation in Ontario: A Renewed Policy Framework*, March 30, 2005, p. 18.

- the clarity of the Board's expectations for the plan.[30]

Particular considerations may arise in the case of government-owned utilities. These entities may pose particular challenges because they are generally considered to be less efficient than investor-owned entities although the empirical evidence on this point is mixed, reflecting the different priorities of different government owners. Government-owned corporations may find it more difficult to align the interests of management and owners with consumers, because politicians may be less focussed on improving efficiency than on pursuing other public policy or political goals, and changes in government can lead to instability.[31]

Typically regulators establish the specific plan components to achieve the identified objectives. This is generally done through a policy consultation or a formal proceeding. Most PBR regimes have automatic rate adjustment formulas, predetermined periods between rate reviews, and reliance on external productivity standards.[32] Specific considerations typically include the following.

- The form of automatic adjustment – typically now either price cap or revenue cap
- The inflation factor – broad or narrow
- Productivity factor – sector-wide or company-specific
- Y-factors – for items which have been separated from the IR/PBR framework[33]
- Z-factors – for extraordinary unanticipated events
- Sharing mechanisms – to share the benefits of efficiency gains in excess of the explicit productivity factor during the term of the IR/PBR
- Plan term – the longer the term the stronger the efficiency incentives
- Reporting requirements – for performance measurement and data capture

---

[30] Ontario Energy Board, *Natural Gas Regulation in Ontario: A Renewed Policy Framework*, March 30, 2005, p. 15.

[31] E. Iacobucci and M. Trebilcock, *The Role of Crown Corporations in the Canadian Economy*, University of Calgary, March 2012.

[32] L. Kaufmann, Incentive Regulation for North American Electric Utilities, in Energy Law and Policy, G. Kaiser and B. Heggie, editors, 2011.

[33] In Ontario the gas utilities have collected the costs of energy efficiency (demand side management or DSM) programs through a Y-factor.

- Off-ramps – backstopping against extraordinary circumstances

3.4 OBSERVATIONS

Since PBR regimes typically are designed to achieve multiple objectives, regulators need to consider the trade-offs among the objectives of the plan. For example, a common trade-off considered by regulators in developing their PBR regimes concerns the adoption of an earnings sharing mechanism. An earning sharing mechanism reduces the strength of the efficiency incentive during the term of a PBR regime. However, this mechanism provides additional benefits to consumers and is perceived to reduce the utility's incentive to over-forecast costs (or underestimate achievable productivity improvements) in applications. The disincentive properties can be limited through the use of a large deadband. Another consideration is that implementing the earnings sharing mechanism can be contentious as there are frequently disputes as to what is to be included. In addition, the timing of earnings can be manipulated, and hence the annual rate-setting process may become more complicated.

Nevertheless, an earnings sharing mechanism may make the overall package more acceptable to stakeholders. Further, since the productivity offset and earnings sharing are two means of capturing a share of the efficiency gains for consumers prior to rebasing, they need to be considered jointly in evaluating the intended sharing of the efficiency gains between ratepayers and shareholders. In essence, in the absence of earnings sharing the productivity target (i.e., the X component in the CPI-X formula) provides "guaranteed" savings to ratepayers with shareholders retaining the full benefit of any additional productivity gains, or bearing a reduced return if the productivity gains fall short of the target. Hence, the more challenging the embedded productivity target the less justification there is for earnings sharing.

To address the concern that the incentive to invest in efficiency initiatives declines through the term of a PBR regime, some regulators have implemented an efficiency carry-over mechanism. This mechanism allows utilities to benefit from efficiency gains beyond the end of the term of a PBR plan.

IR/PBR was originally described as “light-handed” regulation. The formulaic approach of price control regulation was expected to reduce regulatory costs because the PBR regimes tend to be streamlined compared to traditional cost of service regulation, at least initially. It was also argued that price controls streamlined the regulatory process because it reduced the regulator’s need for information as a basis for determining the prudent level of costs. In theory, the efficiency incentive motivates the utility to pursue efficiency without a detailed review. Counter-arguments quickly arose, however.

Observers noted that under a mature price control regime the regulator still needs to undertake comprehensive reviews to establish an appropriate productivity target, to ensure that the utility is optimizing service levels, and to ensure that the utility is prudently managing its operations in the long-run interests of the customers it serves.

IR/PBR seeks to reduce the regulatory burden overall and over the long term, but specific proceedings may well be more resource intensive than a one-year cost of service proceeding. As well, the analytical work to establish productivity measures and assess efficiency performance can be significant. For example, total factor productivity (“TFP”) studies require a significant investment in data and analysis. It is important to consider cost and revenue data carefully – on an aggregated and disaggregated basis – and for both the utility and for a peer group; historical and projected.

As a result, regulators often take specific steps to enhance the efficiency of the regulatory process. One approach is to undertake negotiations or an alternative dispute resolution processes after the regulator has set out the objectives and/or criteria for PBR. Negotiated solutions reduce the burden on the regulator and may be less resource-intensive for all parties than a fully litigated proceeding. A negotiated solution may also increase acceptance by the utility and stakeholders. However, the settlement must be consistent with the principles of IR/PBR and deliver on the regulator’s objectives. A first PBR plan might not be conducive to a negotiated settlement if the regulator is concerned with ensuring a full exploration of the issues and the trade-offs between objectives. However, subsequent rate plans may be more amenable to negotiation once the regulator’s expectations are clear and there is more information about how the utility actually performs under PBR.

4. PBR IN ONTARIO

The Ontario Energy Board ("OEB") has regulated natural gas transportation and distribution rates for more than 50 years, but it has only had rate-setting authority over electricity transmission and distribution since 2001. The OEB's expanded regulatory authority was linked to the industry restructuring that commenced in 1998.

Since 2001, the OEB has set electricity distribution rates using policy frameworks that establish both the overall method and specific analytical tools. The policies are then applied to the specific circumstances of each distributor in individual rate applications. The OEB has used this policy approach because of the large number of distributors[34] and their inexperience with formal economic regulation.

From the outset the OEB determined that incentive regulation would be integral to its rate setting methodology. Not only was the evidence emerging from the international experience with PBR positive, but the OEB had gained experience with PBR in setting rates for the natural gas distributors that it regulates. Furthermore, PBR was seen as an important tool for streamlining the task of regulating Ontario's numerous distributors.

The OEB's regulatory policy framework has evolved since 2001; it is currently implementing the 4th generation of incentive regulation for distributors. It has used a price cap structure from the beginning, but each successive generation of IR has introduced advancements: extended terms, advanced analytical tools including benchmarking, greater attention to utility planning and performance, and more flexibility for utilities.

4.1 OVERVIEW[35]

In 1999, in preparation for taking on responsibility for regulating electricity distributors, the OEB established the PBR Task Force. The Task Force included consultants and stakeholders in a process that developed recommendations for a PBR methodology that

---

[34] Originally there were over 300 local distribution companies. Currently there are about 70.

[35] Additional details are provided in Appendix 4.

would be a practical and effective approach in the context of Ontario's electricity distribution sector.

4.1.1 1ST GENERATION INCENTIVE REGULATION (2001 – 2005)

The focus for 1st Generation IR was to unbundle the rates,[36] incorporate a market rate of return on equity into rates, and set a simple, mechanistic annual adjustment formula. The annual adjustment mechanism incorporated inflation and a productivity factor that was set using a total factor productivity approach (TFP). It was fixed at 1.5%.

1st Generation IR was intended to be in place for about 3 years. However, rates were frozen through legislation; hence, the full incorporation of the market rate of return on equity was delayed, and 1st Generation IR was in place for longer than expected.

4.1.2 2ND GENERATION INCENTIVE REGULATION (2006 – 2009)

For 2nd Generation IR the OEB retained a price cap approach for the annual adjustment mechanism. Rates were rebased through a traditional cost of service proceeding (essentially rate-base rate-of-return ("RB-ROR") regulation). 2nd Generation IR was explicitly intended as a transitional policy until all of the analytical and consultation work could be completed to introduce a more comprehensive longer-term plan (3rd Generation IR). The OEB also developed a handbook which set out guidelines for re-basing applications and provided template models. This approach provided a high level of predictability (because most generic issues were determined in advance) and greater speed of processing, but it resulted in a highly prescriptive framework.

4.1.3 3RD GENERATION INCENTIVE REGULATION (2009 – 2013)

For 3rd Generation IR, the OEB again retained the standard price cap formula approach. However, it introduced two major enhancements: a productivity stretch factor based on benchmarking results and an Incremental Capital Module (ICM) to address distributor-specific capital requirements. The ICM was designed to allow the utilities to increase

---

36 Prior to industry restructuring, rates for generation, transmission and distribution were bundled since Ontario Hydro operated as an integrated utility. Ontario Hydro also reviewed and approved the rates charged by municipal utilities in Ontario.

rates to recover the costs associated with qualifying major capital expenditures, in addition to the formulaic increase that would otherwise be permitted.

The OEB's comparative cost analyses demonstrated that there was a range of productivity levels across distributors. These differences in productivity levels led to the acknowledgement that distributors have different abilities to achieve incremental productivity gains. The OEB assigned different stretch factors to cohorts of distributors based on their prevailing efficiency as determined by the benchmarking analyses.

The cohort allocations were done each year, and distributors had the ability to improve their performance and benefit from a lower stretch factor. Each year several distributors moved between cohorts.

4.1.4 4TH GENERATION INCENTIVE REGULATION (RRFE) (2014 →)

The current policy framework – the Renewed Regulatory Framework for Electricity – was developed through consultations that began in late 2010. The current policy applies to electricity distribution, but the OEB has indicated that it intends to consult on how to apply the principles of RRFE to electricity transmitters as well.

The Renewed Regulatory Framework is a suite of related regulatory policies developed to address specific issues in the sector: government policy (specifically connection of renewable generation), aging infrastructure, customer concerns regarding rate increases, the increased maturity of the industry, and the need to harmonize and consolidate Board policies related to planning and rate setting. It recognizes that in the Ontario context, it was important that the PBR regime not be focused on costs reduction to a degree that would impede the achievement of other policy and performance goals.

The RRFE has three main components:

- Rate-Setting – Distributors must select one of three options, and the choice generally depends on the capital requirements of the distributor. The three options are as follows.
  - 4GIRM: Annual CPI-X rate increases are allowed between rebasing applications that would normally be allowed every fifth year. Utilities are

assigned a productivity factor between 0.0% and 0.6% based on their efficiency factor as determined by the OEB's TFP studies.

- Custom IR, which allows utilities to propose a company specific regime for setting rates over the five year cycle (e.g., pursuant to a five-year cost of service application).
- Annual IR, which allows utilities to defer the normal rebasing in the fifth year and continue to increase rates in accordance with the formulaic escalator, inclusive of the maximum productivity offset.

- Distribution Planning – Distributors must prepare and file five-year plans which integrate capital planning with pacing and prioritization to address their own and regional infrastructure needs.
- Performance Measurement – Distributors must report performance using a scorecard approach, with standards and measures set by the OEB.

The OEB has introduced a rigorous performance monitoring and reporting process. This transparent and highly structured approach highlights the importance of performance across a range of measures. This approach is aligned with the objective of continuous improvement.[37] A scorecard will be used to measure distributor performance on the four outcome dimensions: customer focus, operational effectiveness, public policy responsiveness, and financial performance.

Ontario has not implemented an earnings sharing mechanism (ESM) for electric utilities although ESMs have been accepted for the major gas utilities. Although the Board has not explained it reasoning for this difference, one probable factor is that the inclusion of an ESM necessitates a procedure for making a determination on the earnings to be shared which can be contentious and require significant annual regulatory effort. This effort would be more acceptable for the two major natural gas distributors than it would be for Ontario's 70 electricity distributors.

[37] For further detail, see *Performance Measurement for Electricity Distributors: A Scorecard Approach*, EB-2010-0379, March 5, 2014.

4.2 OBSERVATIONS

The OEB has practiced an evolutionary approach to the development of PBR for electricity distributors. Each framework has been based on a set of objectives that have reflected the circumstances of the sector (the number of distributors, their inexperience in preparing comprehensive applications, growing capital requirements) as well as the government policy framework (unbundling, connection of renewable generation, etc.). Each generation of PBR has introduced refinements to the prior framework, often using more complex analytical tools. This has been possible because of greater access to reliable data and greater stakeholder tolerance for these types of tools. Each generation of PBR has also introduced new elements which respond to concerns raised in the prior generation and also to new developments in government policy.

Over time, the ratemaking framework has become more complex, but it has also been better integrated into other aspects of regulation, including system planning[38] and performance reporting and monitoring. Whereas the early frameworks were quite prescriptive in terms of inputs, the current framework is focussed on outcomes, thus providing greater flexibility for individual distributors. The OEB's expectations around efficiency have also increased: early framework had a modest efficiency factor, whereas the current framework has five different productivity factors ranging from 0.0% to 0.6% that are applied to utilities based on their operating efficiency as determined by the OEB's TFP benchmarking studies.

4.2.1 BENEFITS FOR CONSUMERS AND UTILITIES

The most obvious benefit of the Ontario regime is that the overall cost of regulation is significantly lower than it would have been if traditional cost of service regulation with annual rate applications had been introduced.

The extent to which PBR has resulted in lower rates for consumers is less clear. While there are incentives for distributors to reduce costs, some observers are of the view that this incentive has not been as effective as it would have been if the owners of the

[38] Distributors are now required to file detailed business plans in accordance with the OEB's criteria for Distribution Plans.

distributors were primarily private investors, with a focus on profit, rather than municipalities and the Province. Some municipal owners give higher priority than others to maximizing their return on investment.

In general, the regulatory framework has provided a price constraint which has helped achieve lower rates, while at the same time accommodating other policy objectives. Furthermore, the OEB has explicitly incorporated into its regulatory framework goals that may have short term rate impacts but are in the long term interest of consumers. These other goals include better governance structures, better planning processes and investment in renewed infrastructure and technological innovation.

4.2.2 Disadvantages for Consumers and Utilities

Many distributors found the transition from the historic rate setting process (rates were reviewed by Ontario Hydro, not an independent regulator) to OEB regulation quite challenging. Furthermore, they have expressed the concern that their responsibilities in terms of the regulatory process as well as accommodating other government and OEB policies have increased workloads and costs without all of the cost pressures being explicitly recognized in the rate setting processes.[39] In the view of some distributors, the OEB has implicitly required the utilities to accommodate these added responsibilities through efficiency gains rather than rate increases except to the extent that a utility is able to justify increased costs associated with the added responsibilities at the time of its periodic rebasing application.

Customers have voiced significant concern about the rate increases that have been experienced since the industry was restructured and OEB regulation introduced. However, most of the upward pressure on customer bills relates to other factors including the corporatization of distributors, the implementation of government off-coal and renewable electricity generation policies and the cost of renewing and enhancing Ontario's electricity infrastructure.

---

[39] Costs associated with some costly obligations were explicitly recognized by the OEB. For example, smart meter costs were tracked and explicitly recovered in rates in advance.

4.2.3 Challenges and Implementation Strategies

Building a comprehensive regulatory regime where no formal regulatory regime had pre-existed has been both an opportunity and a challenge. It has been an opportunity because it was not constrained by entrenched expectations and vested interests created by the previous practices. It has been a challenge because all aspects of the regime had to be designed from scratch.

Fifteen years has passed since the OEB began the process of implementing PBR. The regulatory regime has come a long way since 2000, but it is still a work in progress. Key factors in the success achieved by the OEB to date include:

- Developing clear policies using transparent process that allow for significant stakeholder participation;
- Evolving the regime systematically, so that complexity is added in stages as the stakeholders adapt to the increasingly complex system; and
- Maintaining flexibility to adjust to difficulties that arise and respond to the environment, including economic factors and government policy.

4.2.4 Implications for Adopting "Best Practices"

The regulatory regime developed by the OEB has been responsive to the context in which it had to operate: a large number of regulated utilities with limited prior experience with formal regulatory processes, a changing provincial economy (after the 2008 global financial crisis), and a dynamic set of provincial government policies that directly affected the electricity sector. "Best practices" could not be achieved by adopting methods that had proven to be effective in other jurisdictions. Rather, out of necessity, the OEB entered into an extensive and on-going process of developing and evolving a regime that was suited to the Ontario economic and political environment.

Ontario's experience suggest that best PBR practices are most appropriately defined in terms of the process used to design the regime, not in terms of particular design features. The "best practice" involves carefully examining approaches used successfully elsewhere and considering whether they should be adopted – or adapted – to local use.

5. PBR IN ALBERTA

PBR was first introduced in Alberta in 2009 when a regime called Formula-based Ratemaking ("FBR") was approved by the Alberta Utilities Commission ("AUC") for ENMAX Power Corporation ("ENMAX"). This ratemaking methodology was not adopted for the other Alberta distribution utilities until 2013.

The FBR regime used for distributors is a form of price cap regulation. The AUC adopted a five-year term. Initial rates are set to allow recovery of costs as determined in the traditional way (cost of service) in the first year which is the base year for the five-year term. For the balance of the five year term, rates are adjusted using a CPI-X formula. The productivity offset (X) equal the past rate of productivity improvement plus a stretch factor. The AUC determined the historical productivity trend using the Total Factor Productivity ("TFP") approach. TFP is a statistical method that measures productivity by determining the extent to which the increased production, or output, of a firm can be attributed to increases in input factors (i.e., capital and labour). The extent to which the increase in outputs cannot be explained directly by the increase in the input factors is deemed to reflect increased productivity.

The TFP methodology can be used to estimate the historic productivity trend of a company or the industry as a whole. The AUC uses that productivity value as the reference productivity target over the term of FBR regime. However, the AUC assumes that utilities should outperform their historical productivity trend since the rationale for introducing incentive regulation is that the historical productivity performance under traditional cost of service regulation resulted in sub-standard productivity performance. Consequently, a stretch factor is added to the historic productivity performance as determined through the TFP analysis.

The Alberta regime includes a number of features that are seen in some other price cap regimes, including capital trackers, reopeners, an efficiency carry-over mechanisms and service quality performance incentives. These additional features reflect refinements that had been adopted in other jurisdictions to strengthen the incentive effect and to mitigate undesirable cost cutting that harmed quality of service or resulted in insufficient infrastructure investment.

5.1 OVERVIEW OF ELECTRICITY PBR IN ALBERTA[40]

5.1.1 COST OF SERVICE REGULATION

Under the pre-FBR regulatory regime, rates were determined using cost of service regulation. The AUC recognized, however, that the traditional COS regime embedded only a modest incentive to improve efficiency: the approved revenue requirements and resulting rates were based on a two-year forecast of costs. To the extent that a utility was able to realize actual costs that were below its forecast, or if throughput exceeded its sales forecast, the actual net income would exceed the approved level. The utility was able to retain the excess earnings, as is typical of COS regimes. However, it was also recognized that the incentive to realize efficiency gains was quite weak since a pattern of outperforming its forecasts could undermine the credibility of its forecasts in future proceedings. This concern was a key driver for the introduction of Alberta's FBR, as it was in other jurisdictions.

5.1.2 ALBERTA'S FIRST PBR REGIME – ENMAX

The AUC approved a five-year FBR plan for ENMAX effective from January 1, 2007. For ENMAX distribution services, a price cap model was approved and for ENMAX transmission services, a revenue cap model was approved.[41] As noted above, this FBR plan included an inflation factor (I), a productivity factor that included a stretch factor (X), allowances for specific flow-through items, specified reopeners and an asymmetrical earnings sharing mechanism (only gains shared with customers; losses were not).

For the transmission function which relied on a revenue cap rather than a price cap, the FBR plan included a G-Factor for adjustments related to growth capital.

5.1.3 THE INTRODUCTION OF A GENERIC PBR REGIME

In February 2010 the AUC initiated a generic proceeding for the implementation of PBR for natural gas and electricity utilities with the exception of ENMAX since it was already operating under the FBR regime. This proceeding involved a consultation process that

40 Additional details are provided in Appendix 5.

41 AUC Decision 2009-035.

included roundtable meetings and workshops. The AUC engaged a consultant to conduct total factor productivity ("TFP") studies. The utilities were directed to file their proposals in a generic hearing. The AUC subsequently approved the first generation PBR for a five-year term beginning in 2013 for ATCO Electric, Fortis Alberta, ATCO Gas and AltaGas.

According to the AUC, traditional rate regulation had an implicit incentive to maximize costs and to allocate resources inefficiently. In indicating its intention to move to PBR regulation, the AUC set out the following two objectives:

> *The first is to develop a regulatory framework that creates incentives for the regulated companies to improve their efficiency while ensuring that the gains from those improved efficiencies are shared with customers. The second purpose is to improve the efficiency of the regulatory framework and allow the Commission to focus more of its attention on both prices and quality of service important to customers.*

These goals are shared with most regulators that have implemented PBR regimes.

The AUC also set out the following five principles:[42]

> *Principle 1. A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.*

> *Principle 2. A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.*

> *Principle 3. A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.*

> *Principle 4. A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.*

> *Principle 5. Customers and the regulated companies should share the benefits of a PBR plan.*

Again, as can be seen from the Overview sections of this report, these principles are consistent with the guiding principles that are commonly cited when PBR regimes are developed.

---

[42] AUC Decision 2012-237, page 7.

Following are the high-level reasons for the choice of specific factors included in the Alberta model.

- Price Cap formulaic model with stretch factor – This approach was seen to facilitate a smooth transition from COS to PBR while presenting increased opportunities for efficiency gains.
- Five year term – Similar to other regulators that have implemented PBR regimes, the AUC was concerned that a shorter term would weaken the incentive to realize productivity gains. On the other hand, a longer term would delay the implementation of any enhancements to the regime, if required.
- Adjustment factors and reopeners – Like other regulators, the AUC determined that a mechanism for accommodating unanticipated significant cost factors that are beyond the control of management was an important safety valve.
- Capital tracker – This mechanism is designed to accommodate recovery of the costs associated with critical infrastructure investments driven by external regulations or aging assets that the generic formula does not accommodate.
- No earnings sharing mechanism (“ESM”) – The AUC was of the view that having an ESM would weaken the incentives and require increased annual scrutiny. The stretch factor provides sufficient consumer benefit, without the additional benefit sharing that an EDM would provide. This differs from the ENMAX FBR regime.
- Efficiency carryover mechanism (“ECM”) – The AUC was concerned that the Incentives would become weaker later in the five-year term. The ECM maintains the incentive throughout the PBR term and therefore encourages sustainable efficiencies beyond the IR term.

Protection against the deterioration of service quality was seen by the AUC as a key component of a successful PBR regime. The AUC’s model therefore sought to ensure that service quality was not compromised in pursuing cost reductions. The evidence of the PBR proceeding indicates that all parties agreed that some kind of enforcement mechanism was necessary to ensure that the utilities would meet their performance standards. None of the companies argued against penalties for failure to meet service quality targets, when the failure was within their control.[43] Consumer groups were interested in incorporating a penalty scheme into the regime. However, there was concern that a penalty scheme would involve significant burden for utilities and the regulator. The AUC accordingly adopted a penalty mechanism that could be utilized only in the event of clearly unacceptable service quality performance.

5.1.4 EXPECTATIONS FOR THE FUTURE OF PBR IN ALBERTA

As it was a generic proceeding and involved a transition from COS to PBR, the time taken for the proceeding and the decision was long, around 30 months[44]. The AUC expects that the regulatory process will become more efficient as the regulator, utilities, intervenors and customers become more familiar with PBR. The AUC also anticipates that consumers will benefit increasingly over the years from lower rates as compared to the rates that would have resulted if the traditional COS regime had continued. The capital trackers and service quality indicators should ensure that the utilities maintain a safe and reliable network and do not sacrifice customer service in their effort to reduce costs.

The AUC plans to closely monitor the progress of this first PBR regime, in order to learn from experience and adapt the regime as required.

5.2 OBSERVATIONS

Regulators that undertake the transition from cost of service to a performance based regulation regime are now able to take advantage of the experience of the regulators that preceded them down the path to PBR. Doing so helps to avoid the pitfalls of some of the earlier designs. But taking steps to avoid those pitfalls can result in a complex regime.

To manage the process of developing its PBR regime, the AUC first engaged in a consultative process to develop the principles and narrow the scope of the process that would design the actual PBR regime to be implemented. Based on this process, the

[43] AUC Decision 2012-237, page 191.

[44] AUC Decision 2012-237, page 14.

Commission directed the utilities and interveners to limit their proposals to CPI-X based formulas.[45] There could be differences in elements of the model and/or various inclusions and exclusions, but the fundamental expectation was a CPI-X model.

5.2.1 Benefits for Consumers and Utilities

Insufficient time has passed since the introduction of PBR in Alberta to draw definitive conclusions about it benefits or shortcomings. However, it is evident that it was the expectation of significant benefits for consumers and utilities that motivated the AUC to introduce PBR.

The Alberta PBR regime embeds a much stronger incentive to realize productivity/ efficiency gains than the previous COS regime. Consistent with the central purpose of PBR around the world, the Alberta regime delinks rates from actual costs, thereby creating an opportunity for the utilities to pursue improvements in productivity that would increase their profitability. They are permitted to retain the excess profits over the five year term of the plan while bearing any losses resulting from a failure to achieve the level of costs implicit in the approved rate escalation formula.

5.2.2 Disadvantages for Consumers and Utilities

It was generally recognised that some factors affecting a utility's total costs are outside its control, which was the reason for allowing for some adjustments outside the CPI-X mechanism. Nevertheless, some parties continue to be concerned that the inclusion of permitted adjustments outside the CPI-X mechanism such as the capital tracker and Y and Z factors create an opportunity for utilities to exploit loopholes in the cost control regime. In the view of some parties, these features could re-establish the linkage between rates and costs. If such adjustments are significant, rate predictability and stability could be compromised. Too broad an opportunity to flow-through costs outside of the CPI-X mechanism would blunt the PBR efficiency incentives.

On the other hand, from a utility's perspective accommodating all cost pressures within the formulaic rate changes could prove to be very challenging. The model allows for

---

45 AUC Decision 2012-237, page 8.

adjustments outside the formula, but there is an increased burden of providing detailed information in support of the pass-throughs. In addition, there is uncertainty around the acceptance and full recovery of the adjustments until the regulatory treatment has been resolved.

5.2.3 Challenges and Implementation Strategies

The AUC and stakeholders recognized the challenges in the implementation of the capital tracker mechanism. Capital tracker applications require a detailed understanding and testing of individual utilities' proposals. This feature potentially reduces the extent of the streamlining of the regulatory process; however, the AUC clearly considered the benefits of including this feature to outweigh the costs.

The determination of the X factor and the calculation of the TFP involved a highly technical and controversial debate in which consensus was not reached and for which there is no apparent right or wrong answer.[46] In the PBR decision the AUC accepted NERA's TFP methodology and found that the proposed TFP estimate was a reasonable starting point for setting an X factor for Alberta utilities.

To determine the value of the stretch factor, the AUC noted that there is no definitive analysis on which to base its decision analogous to the TFP analysis for the historic productivity trend. Its decision on the stretch factor was consequently a matter of judgment based on qualitative evidence. Parties and the AUC found the stretch factors assigned to electric utilities in Ontario to be informative.[47]

5.2.4 Implications for Adopting "Best Practices"

The PBR model developed by the AUC involved several mechanisms that were designed to address the potential limitations of an overly simplistic CPI-X regime.

It recognized a fixed term PBR model can give rise to the so-called "end-of-term problem" which refers to the problem that the incentive to invest in measures that will produce future productivity gains declines as the end of term approaches., since gains

---

[46] AUC Decision 2012-237, page 86.

[47] AUC Decision 2012-237, page 104.

are normally retained only until the next rebasing. To mitigate this problem, the AUC regime includes an innovative Efficiency Carry-over Mechanism ("ECM"). The ECM was designed to encourage utilities to continue to make cost saving investments near the end of the PBR term. This feature was generally not a feature of the initial PBR regimes that have been adopted in other jurisdictions.

The generic first generation regime, unlike the PBR implemented for ENMAX, did not include an earning sharing mechanism. This approach maximizes the incentive to pursue productivity enhancements. However, it risks ratepayers perceiving the regime to have been overly generous if the utility achieves very high earnings over the term of the plan.

The implementation of a capital tracker resulted in higher regulatory burden than if that feature had not been included. But the feature mitigates the concern that the regime could discourage necessary investments that increase costs without provide offsetting efficiency gains. The AUC anticipates that the benefits of allowing for the pass-through of some specific costs will outweigh the costs in terms of regulatory burden and the risk that the opportunity could be used inappropriately.

6. PBR FOR CONSOLIDATED EDISON

The New York Public Service Commission ("NYPSC") has adopted multi-year rate plans for Consolidated Edison ("Con Edison"), the largest utility in New York.[48] This modified form of COS is referred to in the United States as a type of "alternative regulation". While multi-year regimes generally provide less effective incentives for improving productivity than CPI-X regimes, they do provide greater opportunities for a utility to benefit from efficiency improvements than annual cost of service reviews. Multi-year reviews also tend to reduce regulatory costs. Con Edison's rates are now usually determined for a three-year period which gives the company significant flexibility to change the way it allocates resources during the rate plan term.

Consistent with this flexibility, the NYPSC's reviews of the company focus on the utility's performance and results. Although it is a cost of service regime, rates are set taking into account the company's performance with respect to the established service objectives as well as its test year costs.

The NYPSC's approach has evolved over time and a further review of the ratemaking process was announced In April 2014, when NYPSC staff launched an initiative called "Reforming the Energy Vision."

6.1 OVERVIEW OF CON EDISON RATE REGULATION[49]

6.1.1 THE INITIAL INTRODUCTION OF ALTERNATIVE REGULATION

Before the initial introduction of Alternative Regulation[50] for Con Edison, the approach to utility regulation in New York was based on the traditional cost of service model. Con Edison would annually file its request for rate increases to finance capital investments, recover the operating and maintenance costs. The filing would initiate a formal proceeding by the NYPSC in which the utility, staff and other interested parties were

[48] The NYPSC utilizes confidential negotiations in resolving rate cases, unlike most other regulators.

[49] Additional details are provided in Appendix 6.

[50] The term Alternative Regulation is used in the United States to refer to regimes that do not rely simply on a review of the cost of services. This term is broader than, but includes, IR/PBR regimes.

able to review the rate request of the utility. Under this model, the utility would recover in rates its prudently incurred expenditures and earn the allowed rate of return on its investment (typically referred to as the rate base.

The traditional ratemaking process was substantially transformed in early 90s. Multi-year settlements started to replace annual rate cases and the traditional cost of service approach was augmented by the introduction of targeted performance incentives. The NYPSC adopted indices for measuring the frequency and duration of service interruptions and identifying the worst-performing circuits. Con Edison was required to submit detailed monthly interruption data, and it was subject to penalties or rewards based on its reliability performance.

6.1.2 The Evolution of Consolidated Edison Regulatory Regime

Con Edison's initial multi-year rate plan covered 1992 to1995 and contained a new rate-making approach, known as the electric revenue adjustment mechanism (ERAM). The ERAM was introduced in order to reduce the link between electricity consumption and Con Edison's profits which was a disincentive to achieving success with its electricity conservation programs. Under ERAM, Con Edison revenues were adjusted to offset variances of actual and forecast revenues due to factors that change consumption patterns (e.g., weather). Conservation had no impact on revenue.

In 1995, the NYPSC approved a form of revenue-per-customer cap for Con Edison for a three year term. By determining allowed revenue on a per customers basis, total revenue is allowed to increase based on customer additions, but changes in throughput, either on a per-customer basis or in total, does not have an impact on the allowed revenue. This approach eliminates the impact of weather and conservation programs on the company's revenues. It also stabilizes the amount customers pay for electricity distribution. Since distribution costs are essentially fixed, it was considered appropriate to match revenue per customer to cost per customer.

Con Edison included neither the ERAM nor the revenue-per-customer cap in its next proposal, because the NYPSC rejected Orange & Rockland's revenue-per-customer plan in 1996, indicating that it no longer favoured this approach. The report[51] prepared for NARUC in 1997 noted that problems with PBR in this period were related to categorization of costs (overlapping costs, substitutable costs) and outlined that this could be an important issue for implementation. According to NYPSC reviewing utility accounting procedures can create administrative burden, and asymmetrical treatment of costs may incentivise companies to engage in inefficient behaviour that doesn't lead to improved performance. .

According to the Con Edison's 1997 annual report, the elimination of this mechanism had no material adverse effect on company's financial position or its operations. A report of the Office of Legislative Research states that the period from 1992-1997 was "the peak period for the utility's energy efficiency investments, with average annual investments during this period of nearly $74 million. Rate impacts from this mechanism were minimal. After the decoupling mechanism was eliminated, Consolidated Edison's average annual energy saving investments dropped by nearly half."

In 2003, the NYPSC conducted a study of how the rate structure might create disincentives for the promotion of energy efficiency, renewable energy, and distributed generation. In 2004, the NYPSC released a staff paper summarizing the arguments for and against reinstituting a decoupling mechanism. The report did not recommend reinstituting a decoupling mechanism, and concerns included skewed price signals, large accruals, volatility, and reduced development incentives.

However, in April 2007, the NYPSC directed all public utilities to "develop and implement mechanisms that true-up forecast and actual delivery service revenues and, as a result, significantly reduce or eliminate any disincentive caused by the recovery of utility fixed delivery costs via volumetric rates or marginal consumption blocks."[52] This change was implemented primarily to eliminate any remaining delivery rate disincentives against a utility's promotion of energy efficiency, and behind-the-meter renewable technologies, and other forms of distributed generation. A revenue-per-class decoupling mechanism was approved for Con Edison in 2007. The mechanism has a "trigger" feature meaning that the

51 Performance-Based Regulation in a Restructured Electric Industry.

52 Order Requiring Proposals for Revenue Decoupling Mechanisms, April, 2007.

utility is allowed to file for a decoupling adjustment when the accumulated balance meets the specified threshold.

Con Edison's rate plans contain an earning sharing mechanism. According to NYPSC "the earnings-sharing mechanisms provide incentive for Con Edison to pursue cost efficiencies while at the same time capturing a portion of the benefits stemming from productivity gains during the term of the rate plans"[53]. The multi-year settlements involve longer forecasting periods and period longer than one year imposes the greater uncertainty. In the NYPSC's view, the inclusion of an earning sharing mechanism in the multi-year proposals protects against potential windfalls that may occur because of unpredictability associated with multi-year periods.

To shield against cost reductions that would adversely affect service quality, safety and reliability, the NYPSC developed service quality metrics. Utilities are required to report performance to the NYPSC. Performance is measured against a defined standard. To motivate utilities to meet the standards the NYPSC uses a penalty scheme.

Performance measures and metrics have been improved and strengthen over time. For example, in 2013 the NYPSC adopted a Scorecard as a guidance tool for the quantitative evaluation of electric utility performance in restoring power to customers after a significant outage.

6.1.3 Expectations for the Future of PBR in New York

In April 2014, the NYPSC released "Reforming the Energy Vision" announcing fundamental reforms of the regulatory framework. The report identifies the following potential changes in the ratemaking paradigm:[54]

- **Long term rate plans**: Extending the term of rate plans is expected to create a stronger efficiency incentive. The report recommends rate plans as long as eight years. Reopeners and earning sharing mechanisms are recommended to avoid unintended extreme consequences.

---

53 Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, February 21, 2014.

54 Ibid, page 50.

- **Input versus outcome based ratemaking**: As the utilities are expected to play new roles, the report proposes moving from the traditional input focus to a more outcomes-based ratemaking. By pursuing this approach, there is potential to create long-term customer value. The output measures need to be broad based, quantifiable, and specific enough to produce the intended outcomes.[55] The report acknowledges that purely outcome based ratemaking may not be feasible considering the utility's obligation to serve.
- **Symmetrical versus one-way incentives:** The report acknowledges that traditionally the NYPSC incentives have been asymmetrical, penalties-only adjustments. The report proposes to consider symmetrical incentives to encourage innovation and enhance customer service.
- **Incentives related to capital and operating expenditures**: Under traditional ratemaking, the utilities have no incentive to pursue the objectives of DER (distributed energy resources) or reducing peak demand, because earnings grow with increases in rate base. The report proposes that the Commission consider incentives that encourage the most efficient allocation of capital and operating expenses to align with conservation and demand management objectives.

Given these stated goals, this process will likely lead to consideration, and possibly adoption, of a new regulatory approach that is along the lines of the PBR regimes that have been adopted by other regulators such as OFGEM and the OEB.

6.2 OBSERVATIONS

The NYPSC has for many years adopted performance measures and associated incentives that are similar to those that other regulators have been incorporating into their CPI-X PBR regimes in recent years. The implication is that the adoption of a formulaic approach to setting rates as an efficiency incentive and the adoption of specific performance incentives are separable decisions. Each type of incentive has its

[55] Ibid, page 52

own purpose and each can be adopted as deemed appropriate, based on the concerns that have attracted the attention of the regulator.

6.2.1 Benefits for Consumers and Utilities

While in the view of NYPSC, a three year term may provide benefits to both ratepayers and utilities it is moving to a longer term which it believes will increase the power of the incentive. But it is the view of the NYPSC that this longer term multi-year cost of service regime justifies an Earning Sharing Mechanism to ensure that customers receive an appropriate share of the efficiency gains that are achieved during the longer terms of the rate plans.

6.2.2 Disadvantages for Consumers and Utilities

A multi-year regime that does not use escalators along the lines of CPI-X can be challenging to make operational. The longer the term over which costs are being forecast, the more difficult it is to assess the reasonableness of the forecast costs. Furthermore, a multi-year regime must give the utility flexibility in managing its operations, but without an explicit productivity target that is deemed acceptable along with enforced service standards. It may not be practical to implement a term that is long enough to provide an effective incentive to invest in significant productivity initiatives.

6.2.3 Challenges and Implementations Strategies

Multi-year plans give utilities more flexibility to allocate resources, but without complementary performance standards, that flexibility may result in cost reductions that do not reflect only productivity gains. This concern was noted by the NYPSC:

> *Over the past 10 to 15 years, we and other regulatory commissions across the nation have moved from traditional one-year litigated rate cases to multi-year performance-based rate plans. The purpose of these plans is to allow for rate stability while allowing the utilities greater flexibility in managing their operations. Staff's investigation into this matter suggests that the utilities may not have been placing enough attention and emphasis on safety matters*[56]*.*

---

[56] Report of the New York State Assembly Queens Power Outage Task Force, January 30, 2007.

According the Task Force Report[57] there was evidence that Con Edison reduced its preventive maintenance budgets.[58]

6.2.4 IMPLICATIONS FOR ADOPTING "BEST PRACTICES"

New York is recognized as having a highly reliable electricity system by United States standards. A contributing factor is that NYPSC focuses on performance and reliability measures. The NYPSC introduced performance indicators earlier than other regulators and developed penalty schemes that have been strengthened over the years.

The incentive regimes implemented by the NYPSC in the past, however, have not included strong efficiency incentives. In the absence of credible international benchmarking against jurisdictions with PBR regimes that focus on productivity improvement Con Edison's performance in that regard cannot be evaluated.

This experience does suggest incentives for efficiency and incentives with respect to other performance criteria such as reliability need not be linked. Regulators can determine the performance objectives that they want the utilities they regulate to focus on and can implement incentives that focus specifically on the objectives that are considered important.

However, it needs to be recognized that objectives that have associated incentives are likely to be pursued and may be pursued at the expense of other objectives. An incentive regime that focuses on cost reduction may cause harm in terms of reliability or other areas that are important to consumers. For that reason, once a regulator starts down the path of incentive regulation, it may be necessary to monitor a wide range of performance criteria and ensure that there are comprehensive incentives that appropriately balance the effort undertaken to address the various issue that are important to customers: price, reliability, safety and service to name but a few.

---

[57] Report of the New York State Assembly Queens Power Outage Task Force, January 30, 2007.

[58] See Appendix 6.

7. PBR IN THE UNITED KINGDOM

PBR in the United Kingdom (UK) was triggered by the privatization of the UK energy networks in 1990 and the introduction of competition. The Office of Gas and Electricity Markets ("OFGEM") introduced the RPI-X price control regime for the newly privatized electricity distribution and transmission utilities. This approach was adopted as a means of introducing an incentive for the privatized utilities to improve their productivity while also keeping regulatory costs low. These goals were consistent with the primary goal of Prime Minister Thatcher's privatization policy which was to introduce market discipline into the industry.

The price control regime initially adopted for both distributors and transmitters was a form of price cap. For transmitters the average revenue per MW was capped, with annual adjustments based on an RPI-X formula. The initial rate for each price control cycle was adjusted to reflect the level of costs deemed appropriate by OFGEM. The price control mechanism was modified in 1995 to remove the unintended incentive in the initial design for the utilities to increase their volume throughput.

For transmitters the new regime capped total revenues rather than rates (i.e., total allowed revenue was adjusted by RPI-X annually). For distributors, whose costs were more sensitive to volume, the revised regime adjusted the allowed total revenue annually to reflect changes in volume throughput and customer numbers. Each of these factors was given a 50% weighting. Hence, the total revenue of each distributor was adjusted by 50% of the change in throughput plus 50% of the change in customer numbers, as well as by the RPI-X factor.

The level of the X factor adopted by OFGEM reflected its assessment of the anticipated investment and cost trends over the term of each price control review cycle of 4-5 years.

The basic price cap structure was retained until 2010, although the regime was enhanced at the end of each price control cycle to add incentives that reflected goals other than cost efficiency. In particular, quality of service and capital expenditure incentives were added.

In 2008, OFGEM launched a review of the regulatory regime (the RPI-X @ 20 review) which was completed in 2010. This review was driven by the need to address operational issues within the networks (particularly the need to reinvest to renew aging infrastructure) and to align regulation with government climate change policy. A primary goal of the review was to understand whether the RPI-X model would be effective in fulfilling the new policy objectives of government.[59]

OFGEM issued its final decision report, *RIIO: A new way to regulate energy networks*, in October 2010. RIIO stands for "**R**evenue set to deliver strong **I**ncentives, **I**nnovation and **O**utputs".

The stated objectives of the RIIO model are to drive improvements in network service provider performance in the following areas:[60]

- Putting stakeholders at the centre of their decision-making processes.
- Investing efficiently to ensure continued safe and reliable services at a low cost.
- Innovating to reduce network costs for current and future consumers.
- Contributing to the development of a low carbon economy that will achieve the government's wider environmental objectives.

The key innovation, compared to the prior RPI-X model, is the focus on outputs rather than inputs. This approach aligns the regulatory process with the expectations of customers. The premise of the model is that customers care about results and are not concerned with how those results are delivered. The regime seeks to mimic competitive markets in making service providers responsive to their customers. Hence, under RIIO OFGEM uses a consultation process to set targets that reflect the interests of consumers and establish rewards that will provide effective incentives for motivating the utilities to perform well with respect to those targets. The basis of the incentive is that the network companies have the opportunity to earn higher profits by meeting or surpassing the targets that have been set for them.

---

[59] Alistair Buchanan, Speech at SBGI – OFGEM's "RPI at 20" project – March6, 2008.

[60] Network Regulation-the RIIO Model.

7.1 OVERVIEW OF OFGEM'S EXPERIENCE WITH PBR [61]

7.1.1 20 YEARS OF PRICE CAP REGULATION

Under RPI-X in the UK, the allowed revenue of each utility was set at the beginning of each price control cycle. The allowed revenue was then adjusted annually for each subsequent year during the cycle based on inflation (RPI), the anticipated cost trend taking into account productivity gains (X), as well as other specified factors such as volume changes, customer number changes and capital investment requirements.

The network providers were able to earn net income above the allowed cost of capital that was used to set the base rates if they outperformed the cost assumptions embedded the revenue adjustment mechanism. Early versions of the model focussed on cost efficiency incentives; in later models OFGEM added additional incentives for quality of service.

Since privatisation, each network provider has completed four price control reviews. The form of the price control has changed over time to address perceived problems and new priorities. For example, a number of changes were introduced as a result of an OFGEM review in 2002/2003, including a rolling incentive mechanism, reopeners, and an allowance for pension costs. OFGEM also introduced capital spending allowances to address the need to connect new sources of generation. Flexible mechanisms were introduced in the 4th term to incorporate additional capital expenditure allowances into the allowed revenue of the utilities. In addition, incentives were introduced for capital efficiency. A capex safety net was also introduced to protect against underinvestment: if cumulative investment fell below a defined level, a review was triggered. As these changes accumulated, the RPI-X model became increasingly complex.

By 2010 OFGEM saw the need to develop a new regulatory regime that would encourage a sustainable energy sector. In the face of the new policy and investment drivers, RPI-X was seen to have a number of shortcomings:

---

61 Additional details are provided in Appendix 7.

- The focus of RPI-X was on cost efficiencies. While there was some incentive mechanisms related to service delivery, the relationship between incentives and outputs (financial and non-financial) was not strong.
- The four-year term led network companies to focus on regulatory cycles for their business decisions and not asset life cycles which can be 25 to 40 years.
- The short-term focus limited innovation and the adoption of new technologies.
- The RPI-X regime was not well suited to supporting the push for a low-carbon energy sector.
- The separate incentives for capital expenditures and operating expenditures could potentially bias decision-making.

Hence OFGEM undertook the RPI-X @ 20 Review that resulted in the introduction of the RIIO model.

7.1.2 RIIO Model

The RIIO framework aims to be transparent and proportionate, providing certainty and predictability. At its core, RIIO is a continuation of the price-control model but it sets the allowed revenue on the basis of output targets as opposed to focusing primarily on input cost targets. There are also two elements that are outside the price control regime: an innovation package and the opportunities for stakeholders to play a greater role in the price control process.

The RIIO model is designed to encourage longer term thinking that focuses on a sustainable energy sector by extending the price control term from five years to eight years, including a mid-term review. There are a number of additional expectations:

- Network companies are required to provide well-justified business plans with longer-term context and evidence that alternatives were considered.
- Emphasis is placed on keeping options open when there is uncertainty as to the best method of achieving the performance targets.

- Innovation is encouraged in both the commercial and technical operations of the utilities.
- Network companies and third parties are able to compete for funding from a funding pool for innovation projects.

The RIIO price control regime is based on three elements of revenue:

- Baseline revenue
- Adjustments for performance
- Uncertainty mechanisms

In setting the baseline revenues the network companies must demonstrate to OFGEM the efficiencies of their budgeted expenditures. Business plans form the basis for this assessment. OFGEM use proportionate assessments, which means that the level of scrutiny and the timing of regulatory decisions will depend on OFGEM view of the quality of the business plans and the companies' performance in delivering outputs in previous periods. OFGEM's "assessment tool-kit" for this process includes benchmarking analysis which involves a review of historical and planned costs with less focus on individual category of costs. The network companies may also provide market testing evidence (e.g., surveys) to support their business plans.

In RIIO there is focus on total costs rather than on specific capital and operating expenditure requirements, as was done in the previous regime. Depreciation will be based on the expected economic life of the assets, rather than the physical life which is the traditional approach to establishing depreciation rates.

Under the RIIO model the X-factor has been replaced with three separate incentives:

- Output incentives: The network companies are incentivised on the delivery of primary outputs. OFGEM publishes performance information annually. In the event of repeated failure to deliver on the outputs, OFGEM retains the power to revoke the licence of the network company. The output incentives take the form of adjustments to each utility's allowed revenue.

- Efficiency Incentives: The model allows network companies to gain from efficiencies. The symmetrical efficiency rates are set up-front with no retrospective adjustments. The incentives do not differentiate between capital and operating cost savings so it is similar to, bit more comprehensive than the incentive in the previous RPI-X price control regime.
- Innovation Incentives: Companies bid for upfront funding through a competitive process. The intent is to encourage innovation in a product offering or a delivery process for the long term. Both network and non-network companies are eligible for funding for any stage of the innovation process.

There is also an Information Quality Incentive (IQI) which rewards companies for submitting accurate expenditure forecasts.

From the high-level objectives of the RIIO model, six specific output categories have been developed:

- customer satisfaction
- safety
- reliability and availability
- conditions for connections
- environmental impact
- social obligations

During the price control review, a limited number of primary outputs for each category are being developed through a consultation process. Conceptually, the primary outputs should be material, controllable, measurable, comparable, applicable, and compatible with the promotion of competition and legally compliant.

A critical aspect of RIIO is the level of performance expected of the network service providers. At an early stage, a baseline level of performance for each of the primary outputs will be established, based on consultation and historical performance. The network companies are held accountable for delivering the outputs; hence, incentives have been designed with both rewards for good performance and penalties for poor performance.

The RIIO model requires the utilities to undertake significant stakeholder engagement. This engagement is intended to enable stakeholder views to be built into the programs of both OFGEM and the network companies.

Principles of effective engagement that have been established by OFGEM include:

- Inclusiveness
- Transparency
- Control
- Responsiveness
- Accountability
- Taking views seriously
- Demonstrating impact
- Evaluation

Network companies are encouraged to engage proactively with customers on an on-going basis. The onus is on the companies to determine their individual strategies and to demonstrate how their engagement influences their thinking on what needs to be delivered and how it needs to be delivered. Stakeholder engagement by OFGEM complements the engagement activities of the network companies on policy matters, providing an opportunity for all stakeholders to come together and discuss “big picture” issues.

OFGEM has also initiated a Consumer Challenge Group (CCG). This group includes members who are intended to reflect the expertise and interests of existing and future customers. Their primary role is to ensure that customers’ views are fully considered as part of the price control review process.

7.2 OBSERVATIONS

Regulation in the UK has undergone considerable evolution. The approach that started out as a relatively straightforward CPI-X price control regime became a complex regulatory model. Significant energy was devoted to policy developments and customer concerns about rising costs increased the attention paid to investment planning and customer expectations. The RIIO model is a major transformation of energy regulation in UK.

7.2.1 BENEFITS FOR CONSUMERS AND UTILITIES

The RIIO model places strong emphasis on stakeholder engagement. Network service providers need to demonstrate how their engagement is incorporated into the development of their regulatory and business plans. Companies' applications can be approved on a fast-track basis with a high quality application. This opportunity can reduce the timelines and brings certainty to both consumers and utilities.

The design of incentives for innovation and outputs, in addition to efficiencies, encourages companies to focus on the various outputs that matter to consumers, not just on cost reductions. The increase in term to eight years encourages consumers and utilities to take a longer term view in planning for a sustainable utility sector.

7.2.2 DISADVANTAGES FOR CONSUMERS AND UTILITIES

From the consumer perspective the volume and complexity of the information provided could be overwhelming to assess. To partially mitigate this issue, OFGEM has introduced a Consumer Challenge Group (CCG) to ensure all customer issues are dealt with by a representative group of stakeholders.

For utilities, the greatest challenge is the design of outputs, the associated metrics and level of performance. This is a major change from the regulatory model that they were under before the RIIO model. For example, customer satisfaction is one of the outputs and the utilities need to transform to provide the agreed upon level of customer satisfaction in a cost-effective way.

The network companies are expected to incorporate environmental objectives into their applications. With external environmental views and regulations continuously evolving, the companies will be challenged in the design of outputs on these objectives.

7.2.3 Challenges and Implementation Strategies

The RIIO framework has not been tested in any other jurisdictions. While the conceptual merits of the model are recognized by all stakeholders, the major disadvantage for consumers and utilities is the uncertainty of its practical application, as well as the onerous process of setting targets and the timelines for the price control determination.

7.2.4 Implications for Adopting "Best Practices"

The OFGEM experience demonstrates how a relatively simple PBR regime can become complicated as modifications are introduced to address concerns that arise and the increasing expectations of government and consumers. To some extent, this growing complexity is a reflection of the need to address quality of service issues that encompass a broadening range of consumer expectations[62] as well as a growing spectrum of government policies that create complex industry objectives.

The RIIO model is a comprehensive incentive model developed with the goal of embedding long-term thinking for a sustainable energy sector. The challenge for the regulator is to be flexible and adapt to the changes as the term progresses while still adhering to the principles that were established when the RIIO model was initially introduced.

[62] For example, consumer expectations related to the timeliness and comprehensiveness of information they can access is ratcheting ever upward as a result of digital technologies.

8. PBR IN AUSTRALIA

In 1998 the National Electricity Market ("NEM")[63] was created following a process coordinated by the Council of Australian Governments. The creation of the NEM culminated with a reform of the electricity industry. Pursuant to the National Electricity Law, the Australian Competition and Consumer Commission ("ACCC") was initially made responsible for the regulation of distribution and transmission networks effective July 1, 1999. The Australian Energy Regulator ("AER")[64], currently regulates electricity transmission and distribution while the ACCC has a policy role.

Prior to 1999, rates for electricity service providers were set using traditional cost of service regulation. With the introduction of the NEM, however, the traditional rate setting methodology for electricity transmission service providers was replaced with a revenue cap regime based on forecast costs over a five year term. Within the term, rates are smoothed using a CPI-X escalator. This mechanism provides an efficiency incentive since variances from the annual allowed revenue are retained by the utility. The 3rd five-year term under this regulatory regime concluded in June 2014.

The fundamental design of the revenue cap has not changed since incentive based regulation was introduced in Australia. However, it has evolved with the incorporation of enhanced customer consultation, improved regulatory processes and stronger incentives.

In 2013, the AER undertook the Better Regulation Program. The objective of this program was to deliver an improved regulatory framework focused on promoting the long term interests of electricity consumers. The current transmission regulatory term is under development for the 2014-2019 period and is implementing changes in accordance with the Better Regulation Program.

---

63 The NEM interconnects five regional market jurisdictions (Queensland, New South Wales, Victoria, South Australia and Tasmania). West Australia and Northern Territory are not connected to the NEM.

64 The AER is the successor of the Australian Competition and Consumer Commission (ACCC) who was the industry regulator of network providers in the National Electricity Market ("NEM") until this role was transferred to the AER in 2005.

8.1 OVERVIEW OF INCENTIVE REGULATION IN AUSTRALIA[65]

8.1.1 THE INITIAL INCENTIVE REGULATION MODEL

In developing the new regulatory regime for transmitters (and distributors) in 1999, the ACCC observed that the previous cost of service regime did little to encourage efficiency improvements. The previous regulator had found it challenging to determine the level of rates that would support efficient operations while identifying and eliminating costs that resulted from embedded inefficiencies. It recognized the problem that the regulatory literature had identified that cost of service regulation provides an implicit incentive to undertake excessive investments with no effective counter-balancing mechanism to identify and disallow inefficient operating and maintenance expenses.[66]

To address these concerns the ACCC implemented a revenue cap regime.[67,68] The term of the revenue cap is five years, with allowed revenue being established based on an approved forecast of operating and capital costs over a five-year term. The allowed revenue was set for the first year in each term and a CPI-X escalator was then used to adjust the allowed revenue annually within the term to account for inflation minus a productivity offset.[69] The initial level of allowed revenue and the revenue escalator were set so that the present value of the allowed revenue over the term would be equal to the present value of the allowed costs over the five years. In doing so, the ACCC also ensured that there would not be any rate shock in the transition from the end of one term to the beginning of the next term or within the term.

---

65 Additional details are provided in Appendix 8.

66 Australian Competition and Consumer Commission. Final Decision. Access Arrangement by Transmission Pipelines, Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System; Access Arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System; Access Arrangement by Victorian Energy Networks Corporation for the Principal Transmission System. October 6, 1998.

67 Ibid.

68 Similar regimes were implemented for gas utilities as well as for electricity transmission and distribution service providers.

69 Depreciation rates were based on economic service life of assets rather than the physical life.

The ACCC's goals in implementing this regime were to:

- encourage network providers to improve efficiency and reduce operating costs by allowing them to retain any excess earnings that were realized by keeping costs below the allowed revenues; and
- encourage efficient capital investment by allowing the service providers to retain the differential between the allowed forecast and actual capital costs.

The ACCC also recognized the importance of including an explicit level of service in the incentive regime. Consequently, from the outset the regulator required that transmission providers file a set of service standards and the proposed benchmarks for each standard as part of their transmission revenue cap proposals.

8.1.2 The Evolution of Australia's Incentive Regulation

At the end of the initial PBR term (1999-2004), the ACCC introduced an incentive mechanism for capital expenditures that was intended to ensure that the transmission providers would select efficient capital projects at the lowest sustainable cost for a given level and quality of service. This incentive was specified as a capital expenditure target for each year of the regulatory term and was established at the start of each regulatory period. The mechanism allowed transmission providers to retain the depreciation and return on the difference between the actual and allowed expenditure for the remainder of the five-year term.

With respect to operation and maintenance expenditures, in 2004 the ACCC observed that under the initial incentive regulation model transmission providers faced incentives that decline over the regulatory period; i.e. if a transmission provider made efficiency gains in the first year of the five year regulatory period any benefit would last for four more years before the allowed operation and maintenance expenditures were updated. As such, the benefit was significantly reduced as the implementation of the efficiency gains approached to the end of the regulatory period. The ACCC's changes to the PBR regime therefore included the introduction of the efficiency carry forward mechanism. Through this mechanism a transmission provider is able to retain the benefit of incremental efficiency changes for five years after the year in which that incremental change is made. The efficiency carry forward mechanism was designed to strengthen the efficiency incentive for operating and maintenance expenditures in the later years of the regulatory term. It resulted in a nearly constant incentive to achieve efficiency gains over the course of the regulatory term. Initially this efficiency carry-forward mechanism applied only to operating and maintenance expenditures.

In 2007 as it prepared for the third PBR term in 2007, the regulator implemented an Efficiency Benefit Sharing Scheme ("EBSS") which modified the efficiency carry forward mechanism. It viewed this feature as not only an incentive mechanism but also as a method of sharing the present value of long term benefits of efficiency gains between consumers and the utility in a pre-defined ratio.

The AER's design goal for the EBSS mechanism was to share efficiency savings or losses in a ratio of approximately 30:70 between the transmission service provider and users of the transmission network. The EBSS currently remains in place and the AER has indicated that it will be reconsidering the appropriateness of this carry-over mechanism and the sharing ratio only if the transmission provider presents evidence that it is approaching the efficiency frontier (i.e., the point where there are no further efficiency gains to be realized).

8.1.3 BETTER REGULATION PROGRAM

In 2013, the AER undertook its Better Regulation Program to enhance the approach to be used in regulating electricity networks. The Better Regulation Program brought together a number of reforms to enhance the regulatory model, including new annual reporting on efficiencies, new tools to assess business expenditure forecasts, stronger incentives, an alternate way to determine the allowed return on investment and a better consumer engagement framework.

The Better Regulation reforms included enhancements of the incentive for capital expenditures. As it had previously noted in the context of operating and maintenance expenditures, the AER observed that under the existing incentive regulatory regime transmission providers faced incentives to undertake capital expenditures that declined over the regulatory period. The AER also noted that these incentives led to inefficient capital expenditures and inefficient substitution of operation and maintenance expenditures for capital expenditures toward the end of a regulatory period.

The resulting changes in the capital expenditures incentives were as follows:

- The AER introduced a Capital Expenditure Sharing Scheme ("CESS") to share efficiency gains and losses between transmission providers and network users.
- It allowed transmission providers to use actual depreciation to roll forward into the regulatory asset base.
- It included new ex-post measures to ensure that network users do not bear the costs of inefficient or imprudent overspend or capitalized operating expenditures.

The CESS was intended to encourage efficient capital investment decisions by providing a network service provider with the same value of rewards and penalties in relation to capital expenditures regardless of which year within the PBR term the saving or loss is realized. Through the CESS mechanism the savings and losses are shared with the transmission service provider retaining 30% of any savings while network users receive 70% of the benefit of below budget capital costs.

The 30/70 sharing component of the CESS aligns with the sharing ratio of the efficiency benefit sharing as specified for the EBSS. Since the incentives are balanced, if a transmission service provider capitalizes operation and maintenance expenditures it will benefit by 30% through EBSS but, as a result of the introduction of the CESS, that benefit is offset by the 30% penalty from the CESS.

8.1.4 SERVICE STANDARDS

Service standards are an integral component of Australian incentive regulation for transmission utilities. From the outset, the regulator was aware of the risk that a transmission provider may reduce cost by reducing service quality. As earlier indicated, the AER therefore required transmission providers to propose a set of service standards and benchmarks for each standard as part of their regulatory review application. The transmission service standards that are used have evolved over the years.

In the ACCC's 1999 decision in respect of the first transmission revenue application for transmission providers, the service standards regime was still being developed. In 2003, the ACCC released its Service Standards Guidelines which set out its approach for setting performance incentives within the transmission revenue cap process. The Service Standards Guidelines outlined the ACCC's information requirements to implement the service standards performance incentive scheme. The Guidelines set the requirement for transmission providers to report on service standard performance on an annual basis and allowed any reward/penalty to be incorporated into transmission providers' charges for the subsequent year.

In 2007 the AER issued its first service target performance incentive scheme. According to the fourth version of the service target performance incentive scheme ("STPIS") issued in 2012, the role of the STPIS is as follows:[70]

- It defines the performance incentive scheme parameters that specify how a transmission network service provider's network reliability and market impact is measured;
- It sets out the requirements with which the values to be attributed to the parameters must comply;
- It is used by the AER to decide the service target performance financial reward or penalty component of a transmission determination; and
- It provides guidance about the approach the AER will be taking in reviewing a transmission provider's service target performance and explains how this will affect the transmission provider's maximum allowed revenue.

Under the current regulatory approach, past spending is used as a starting point for setting future expenditure allowances on the condition that the regulator is satisfied that past spending is efficient. If a service provider is efficient and has been responding to expenditure incentive measures, past expenditure will be a good indicator of how much it will need to spend in future. If the business is not responding to incentives, the AER is

---

[70] Australian Energy Regulator. Electricity transmission network service providers Service target performance incentive scheme. December 2012.

sets forecasts with reference to benchmarks reflecting efficient costs. The AER uses a wide range of techniques to assess expenditure proposals and set efficient expenditure forecasts. The techniques used include:[71]

- Economic benchmarking, productivity measures are used to assess business efficiency overall.
- Category level analysis is used as a key benchmarking tool to compare how well a transmission provider delivers services for a range of individual activities and function; this tool provides a comparison of the transmission provider over time and against peers.
- Predictive modelling and statistical analysis are used to predict future spending needs, currently used to assess the need for upgrades or replacement as demand changes (augmentation capex, or augex) and expenditures needed to replace aging assets (replacement capex, or repex).
- Trend analysis is used to forecast future expenditure based on historical information, particularly useful for operation and maintenance expenditures where spending is largely recurrent and predictable.
- Cost-benefit analysis is used to assess whether the business has chosen spending options that reflect the best value for money.
- Reviews of detailed engineering plans are used to assess specific proposed projects or programs.
- Reviews of processes, including assumptions, inputs and models that the network provider has used to develop its proposal are also relied on.
- Governance and policy reviews, including examination of the business's strategic planning, risk management, asset management and prioritisation are also used to assess the business efficiency at a high level.

71 Australian Energy Regulator. Overview of the Better Regulation reform package, April 2014.

8.2 OBSERVATIONS

The Australian revenue cap incentive regime for transmitters can be viewed as a five-year cost of service regime that sets a smoothed revenue trajectory over the five year term based on projected costs for the period. The costs used to establish the five-year revenue requirement become the target cost for the PBR regime. The transmitter has an incentive to reduce costs while meeting its established service quality standards since it is able to retain a share of the savings that are realized. The sharing mechanism appears to serve as an alternative to using a stretch target as a means of flowing a share of the benefit of productivity gains through to consumers.

8.2.1 BENEFITS FOR CONSUMERS AND UTILITIES

The smoothing of the annual increases in transmission revenue is explicitly incorporated into the design of the Australian regime. This is not a standard feature of PBR regimes elsewhere although it tends to be an implicit outcome of CPI-X regimes. Smoothing the required rate increases is attractive to customers.

The smoothing should not be harmful to utilities since the allowed revenue is set at a level that equals the allowed costs on a present value basis. Conceptually, this feature could raise cash flow concerns but that problem is unlikely to occur in a stable environment where the transmitter has access to capital.

The Australian regime also appears to be somewhat unusual in seeking to realize an explicit sharing ratio of the benefits between consumers and the utilities, with 70% of the savings being the consumer share.

8.2.2 DISADVANTAGES FOR CONSUMERS AND UTILITIES

Although there is no definitive evidence on the impact of earnings sharing on the response of utilities to the incentive, many regulators have endorsed the view that the incentive to realize efficiency gains is greatest when the consumer share of benefits is built in to the regime by including it in the productivity target (i.e., the X factor in the CPI-X escalator) which results in 100% of any productivity gains above the target flowing to the bottom line of the utility. Of course, since the consumer share is embedded in the X factor, the utility must achieve at least that level of productivity gains in order to earn its full allowed return on capital.

If the Australian design has the effect of weakening the efficiency incentive, then the magnitude of the total benefit will be reduce, which would imply that both the consumers and the utilities could realize less benefit.

8.2.3 Challenges and Implementation Strategies

The Australian regulators recognized that under a PBR regime that focuses on cost reductions, service quality could be compromised. To address this concern, they adopted service quality measures that the transmitters were required to maintain. The fact that this feature of the PBR regime has been enhanced over the years may imply that the regulator has not been confident that this feature has always been successful in realizing the intention of avoiding cost reductions that have compromised service levels.

Service levels are affected by many factors that are beyond the control of the utility. As a result, quantitative measures of service quality can be difficult to use in a manner that truly reflects performance when imposing penalties, or giving reward, to a utility for its cost of service results.

8.2.4 Implications for Adopting "Best Practices"

The Australian experience reconfirms the observation in other jurisdictions that there is no single best practice for PBR. Each regime is tailored to the expectations of consumers and government policy within that jurisdiction. The simple conclusion regarding best practices is that the objectives of PBR need to be clearly defined so that the regime that is implemented is appropriate for those objectives. It must also take into account the structure of the industry being regulated.

Beyond that, the Australian experience also demonstrates that PBR regimes need to balance stability and predictability with flexibility. Stability and predictability are important given the need for utilities to be able to know the context within which they will operate when they are developing their investment plans. However, flexibility is needed so that a PBR regime can be modified to address identified shortcomings and also to accommodate changing economic and market conditions as well as evolving government policies that impact on the industry.

Australia's model also highlights the observation that in a complex incentive regime it is necessary to ensure that the individual features provide incentives that are consistent and aligned. CESS, EBSS and STPIS were explicitly designed to be complementary.

It is also notable that the AER has developed over the years and currently uses a wide range of techniques, model and tools to assess expenditure proposals and set efficient expenditure forecasts. Since no measure is perfect, a diverse tool box can be an effective way to realize the principles such as those set out in AER's expenditure forecast assessment guidelines: validity, accuracy, and reliability, parsimony, robustness, transparency and fitness for the purpose.

9. PBR IN NORWAY

Rates for electric distribution and transmission utilities in Norway have been set using a performance based regulation regime since 1997. The approach adopted by the Norwegian regulator, the Norwegian Water Resource and Energy Directorate ("NVE")[72] was a revenue cap based on benchmarking. This regime is now in its fourth term. Although the fundamental approach has not changed since the PBR regime was initially introduced, NVE has evolved the benchmarking methodology with each new regulatory period. It has also expanded the scope of incentives to take into account performance factors other than cost reductions. The current methodology is being used to set rates annual for the years 2013 to 2018.

Since Norway has a single dominant transmission company (Statnett), NVE has relied on international benchmarking as a basis for establishing its allowed revenue.

The stability of the Norwegian regime has the benefit of providing a high degree of regulatory certainty for all stakeholders. The main goals of the refinements have been (i) to maintain confidence that the revenues allowed for each utility are sufficient for the utilities to attract investment while requiring continuous productivity improvement and (ii) protect against cost reductions that compromise system reliability.

9.1 OVERVIEW OF ELECTRICITY PBR IN NORWAY[73]

9.1.1 THE INITIAL INTRODUCTION OF PBR

Prior to 1997, rates were set for regulated electricity distributors and transmitters in Norway on the basis of traditional cost of service. It appears, however, that in the 1990's, if not earlier, the NVE became interested in alternate forms of regulation that would achieve improved efficiency in the sector and lower rates for consumers over time. Like regulators around the world, the literature on economic regulation convinced

[72] Approximately 90% of power generation in Norway is hydroelectric; hence, the Directorate is responsible for water resources and electricity. Furthermore, like Quebec, its hydroelectric generation provides it with significant storage capacity which provides flexibility to meet daily, weekly and seasonal load variances with limit diversity of supply.

[73] Additional details are provided in Appendix 9.

the NVE of the shortcomings of the conventional costs of service regulatory models including cost of services regulation. Furthermore, NVE undoubtedly would have observed with interest the success of the price cap regime introduced by OFGEM in 1990. Both theory and practice provided justification for moving beyond cost of service regulation to some form of performance based regulation.

NVE contracted the Foundation for Research in Economics and Business[74] to investigate efficiencies in the electricity sector. Its work, which built on earlier empirical analysis, estimated that 25% of industry costs resulted from inefficiency which led to the conclusion that there was a strong need for a regulatory regime that would provide an incentive for the utilities to become significantly more efficient.

Upon completion of the report, the NVE organized consultations with the industry to review the recommendations of the consultants before implementing its initial PBR plan. The new regime focused on providing an incentive for the utilities to pursue efficiency gains so as to reduce costs and hence future rates. The essential features of the initial regime were:

- The allowed revenue of each grid company[75] was set annually based on benchmarking of costs against comparable firms.
  - NVE determined that there were enough Norwegian distribution companies to base the efficiency benchmarking for distributors of the historic costs of the industry.[76]
  - Norway's dominant transmission operator (Statnett SF) was benchmarked against Sweden's transmission operator.

---

74 Finn R. Førsund , Sverre A.C. Kittelsen, 1995.

75 The electric grid in Norway is divided into three levels: distribution grid with 198 owners, regional grid with 106 owners and central grid with 37 owners. The central grid is a national "backbone" transmission system operated by Statnett SF which owns about 96% of the central grid. Since the implementation of PBR, merger have reduce the number of distribution owners to 136, and the number of regional owners to 86 and number of owners of central grid facilities to 18.

76 The NVE's benchmarking was based on a statistical methodology known as Data Envelopment Analysis ("DEA") using 1994-1995 data for the electricity distributors in Norway.

- The benchmarking studies were used to establish cost norms – or allowed costs – for each utility. Since the costs norms were based on historic cost data, the results were adjusted for inflation before setting the allowed revenue on the basis of the allowed costs for the rate year.
- The variance between actual and allowed revenues was captured in a variance account and disposed of to customers in future years.
- Extreme over- and under-earning was restricted since the regime included a minimum (2%) and a maximum (15%) permitted return on capital. Returns outside this collar triggered a rate adjustment that varied the permitted revenue.

This PBR regime provided a significant incentive for the regulated electric utilities to operate more efficiently: because revenue was fixed, the sole determinant of profit was the utility's costs. Any reduction in costs would result in an equivalent increase in profitability since the scheme did not include an earnings sharing mechanism. Further, to earn the return on capital embedded in the cost benchmark, each utility had to match or outperform the benchmark. Firms with costs above the benchmark would suffer sub-standard returns.

In addition, since the distributors were benchmarked against themselves as an industry, each company's success in increasing its efficiency served also to lower costs for the distribution sector as a whole, thereby lowering the benchmark in future years.[77]

9.1.2 THE EVOLUTION OF NORWAY'S PBR REGIME

The initial regime was implemented for the period 1997-2001. The methodology used to benchmark the utilities was refined for the second five-year term which the NVE implemented for the period 2002-2006. It also expanded the scope of the performance incentives to address factors other than cost.

More specifically, in preparation for the second term, the NVE introduced in 2001 an additional incentive mechanism related to system reliability, known as CENS[78]. CENS

[77] The time lag for the yearly updates was two years due to the time required to audit the data and complete the analysis. Hence, there is an opportunity for the utilities to benefit from efficiency gains for two years even if equivalent gains are achieved by the industry as a whole.

was used to adjust the allowed revenue in the subsequent year based on each utility's reliability performance; hence, the first year in which the allowed revenue took into account CENS performance was 2002, the beginning of the second PBR term.

NVE also enhanced its benchmarking for Statnett, the main transmission operator since it recognized the inherent weakness of benchmarking against a single comparable firm. NVE improved the benchmarking of transmission costs by partnering with regulators from Austria, Denmark and the Netherlands to undertake international benchmarking of their transmission grids. The project resulted in a model called ECOM+[79] that the NVE began using to determine the allowed revenue for Statnett starting in 2003

For the third PBR term, 2007-2012, NVE further expanded its benchmarking for Statnett. It was able to replace the four country ECOM+ study with the e3grid study which currently includes 22 European Transmission System Operators ("TSO") and utilizes a more sophisticated methodology.

The NVE also revised the methodology used to establish the company-specific allowed revenue for distributors. For the third PBR term, NVE began to base the allowed revenue on actual costs as well as the cost benchmarks.[80] This change appears to recognize the concern that no benchmarking study can take into account all factors that affect the comparative costs of an electric utility; hence, basing allowed revenue entirely on standardized costs based on a benchmarking study will not be completely equitable for all companies. Over time, as industry efficiency gets closer to the maximum potential efficiency, some firms will inevitably find it easier than others to beat the benchmark due to inherent differences that are not captured by the benchmarking study.

Additionally, it was observed that in the previous terms, in the event of a merger, the revenue cap for the merged firm was less than the sum of the revenue caps of the

---

78 CENS, Costs of Energy not Supplied, is based on cost data for the estimated energy not supplied and average interruptions.

79 The ECOM+ model is essentially a unit cost measure. It benchmarks the cost of operation and maintenance (OPEX), and capital cost of new network facilities (CAPEX).

80 In determining the allowed revenue, the individual company's actual costs was given a 40% weighting and the "cost norm" based on the benchmarking study was given a 60% weighting.

individual firms. This result occurred because the benchmarking model had identified economies of scale – hence, the cost norms for larger utilities were proportionately lower. This result was a disincentive to mergers and acquisitions which was clearly contrary to the public interest based on the finding of scale economies which suggested that mergers, all other things being equal, should result in lower costs. The NVE therefore introduced in 2007 a mechanism to reflect in the revenue allowed for a merged distribution entity an adjustment that would allow it to earn, on a present value basis, the equivalent of 10 years of the difference between the revenue allowed the merged distributor as compared to the total revenue that would have been allowed for the individual distributors had they not merged.

The current PBR term, 2013-2018, has seen further evolution of the regime.

- NVE adopted a new cost of capital model that resulted in an increase in the allowed weighted average cost of capital ("WACC") used for setting the allowed revenue.
- Benchmarking is based on five-year average data rather than a single year.
- The time period for which lost allowed revenue resulting from a merger was recognized was increased from 10 to 30 years.
- Costs related to participations in research, development and pilot projects are added to the allowed revenue up to 0.3% of a company's regulatory asset value.[81]

The revision to the methodology used to determine the allowed cost of capital was implemented because the 2008 financial crisis had altered some of the implicit assumptions embedded in the model that had been used previously. NVE accepted the complaint that its allowed cost of capital was lower than the rate allowed in other European jurisdictions.

The more generous treatment of expenditures related to research, development and pilot projects reflects the longer term benefits of investing in the introduction of new

[81] Previously they were able to recover only 40% of these costs as an adder to the allowed revenue.

technology, such as smart meters and smart grids. Full recovery of these costs was seen as necessary to mitigate the disincentive that previously existed. The benefits of these types of expenditures are realized by the industry generally, not just the individual utility. In the absence of full recovery, there was an incentive to underspend on these types of projects since the cost are borne internally while the majority of the benefits are realized externally – by other firms that benefit from the learning that results and by society generally.

9.1.3 EXPECTATIONS FOR THE FUTURE OF PBR IN NORWAY

NVE has evolved its PBR regime with each regulatory period of roughly five years. This trend is expected to continue. However, since Norway is in the early years of its latest PBR term, it is difficult to anticipate how the system is likely to evolve after 2018.

At a general level, it can be expected that if there are specific concerns with the extent to which the incentives inherent in the regime align with the public interest, efforts will be made to ensure that the interests of the regulated utilities and the public as closely aligned as possible. Furthermore, if there is evidence that the regime disadvantages some companies, the regime is likely to be modified to make it more equitable.

9.2 OBSERVATIONS

The central features of the Norwegian PBR regime have been in use since 1997:

- The regime is a form of **revenue cap**. NVE determines each regulated utility's allowed total revenue annually. Rates are then set at the level necessary to generate the allowed revenue based on a forecast of throughput. The variance between the allowed revenue and the actual revenue in any year is captured in a deferral account and disposed of to customers in subsequent years.

- The allowed revenue is determined on the basis of a benchmarking study. The approach to benchmarking use by the NVE has evolved in an effort to ensure that the benchmark is as equitable as possible for both consumers and the regulated utilities.

Benchmarking establishes cost norms based on the performance of the utilities included in the benchmarking study that is used; hence, the average level of inefficiency is reflected in the cost norms. Efficiency improvements result from the opportunity to increase profit by outperforming the benchmark. This approach is most effective when the regulated utilities are included in the benchmark since the inefficiency embedded in the benchmark will decline as the individual entities become more efficient, as has been the case for Norway's distribution utilities.

NVE initially benchmarked the transmission operator, Statnett, against a single external transmission operator. While this provided an effective incentive for Statnett to increase its profit by improving the efficiency of its operations, the regime did not result in the benchmark also becoming more rigorous as a result of these efficiency gains. NVE had to collaborate internationally with other regulators in order to develop a benchmarking regime for transmission that included this "feedback loop" with the benchmark reflecting a higher degree of efficiency as the regulated firms responded to the incentive and implemented internal efficiency measures.

In Quebec, both the distribution and transmission divisions of Hydro Quebec dominate within the province; hence, if international benchmarking is used, it may be necessary to establish similar collaborations if there is a desire to develop a design with a comparable feedback loop.

The NVE approach makes no attempt to define the costs of an efficient firm to use as the basis for determining allowed costs.

9.2.1 BENEFITS FOR CONSUMERS AND UTILITIES

The regime has served as an effective incentive for the regulated distribution and transmission utilities to become more efficient. NVE has not considered it necessary to make fundamental changes to the methodology, although it has constantly pursued opportunities to improve the benchmarking to ensure that the costs norms on which the allowed revenue is based are realistically achievable while ensuring that the incentive for continuous productivity improvement is effective.

Utilities have been able to realize returns on investment that exceed the allowed rate by reducing costs to a level below the cost norm determined through the benchmarking studies. The inherent lag in updating the benchmarking study allows each regulated firm to benefit from productivity gains even if its rate of reduction in its costs is no better than the industry average.

Consumers have benefited from the resulting efficiency gains which are believed to have resulted in lower rates than would have been allowed under a traditional cost of service regime.

9.2.2 Disadvantages for Consumers and Utilities

The concerns that have been identified do not appear to be inherent disadvantages of this form of performance incentive. The issues that have emerged, and have been addressed, are discussed below, in the challenges section.

9.2.3 Challenges and Implementation Strategies

Since the cost norms for individual firms were initially based on the benchmarking studies, it was inevitable that each firm's starting point would be different. While on average all distribution firms had costs that corresponded to the cost norms that resulted from the benchmarking studies, some individual distributors would have entered the new regime with costs that were above their cost norm, others would have started out with costs below their cost norm. The former would have had to achieve efficiency gains just to realize the allowed return while the others would have earned superior returns with no effort.

To the extent that the costs of individual firms relative to their cost norms as determined by the benchmarking studies reflected differences in their efficiency, these differences would be equitable. It would be the least efficient firms that would have to strive the hardest just to earn the allowed return. However, to the extent that the deviations from the cost norms reflected imperfections in the benchmarking studies, this result could be viewed as inequitable across the regulated distributors.

For Statnett, the transmission operator, the starting point was determined by the relative efficiency and inherent cost differences in the firm it was benchmarked against.

Arguably, inequity due to the inherent lack of precision in any benchmarking study when applying the results to individual firms, each of which will have some unique cost pressures, is not a serious drawback when the level of embedded inefficiency is high and there are many opportunities to improve.

However, as the industry as whole becomes more efficient and opportunities for further gains become more challenging, the importance of good benchmarks increases. NVE has made significant effort to improve its benchmarking with each new PBR term, as the presumed efficiency of the industry as a whole has improved making further productivity gains harder to achieve.

From the perspective of consumers, any effective incentive regime will cause the utilities to focus on improving in areas addressed by the incentives at the expense of other issues that matter to consumers. A regime that focuses on reducing costs and rates will tend to compromise aspects of service quality that are not explicitly monitored within the incentive regime. Hence, NVE had to implement specific incentive related to system reliability in order to limit the tendency to allow unmeasured areas of service quality to deteriorate as a result of cost cutting.

9.2.4 Implications for Adopting "Best Practices"

The Norwegian model appears to work well and provide an effective incentive for improving efficiency. It must be noted, however, that the regime is not necessarily replicable in other jurisdictions.

- Internal benchmarking requires a large enough sample of firms to permit analysis that generates statistically significant results for the costs associated with the important characteristics (i.e., cost drivers) of electric utilities. Internal benchmarking cannot be undertaken for an industry with a single dominant service provider.
- External benchmarking requires a cooperative effort so that the required data can be collected on a consistent basis, and be audited for accuracy.

Although the precision of cost norms may not be critical to a regime when the regulated firms are very inefficient, the more efficient the firms that are regulated the more critical it is that the cost norms are accurately estimated so that the allowed costs are realistically achievable. It is therefore acceptable to introduce PBR with cost norms based on imprecise benchmarking studies and then evolve the quality of the benchmarking over time as the regime drives inefficiencies out of the industry.

Given the incentive to compromise service quality, if it is not embedded in the PBR regime, consideration should be given to the best way to monitor aspects of service quality that matter to consumers, such as the adequacy, reliability and safety of electricity service. Appropriate incentives are need to counterbalance the cost-cutting incentive to ensure that service quality is not unreasonably compromised.

NVE appears to have maintained a constructive relationship with industry by engaging in joint workshops and regular communications about issues as they arise. At each stage of the evolution of the regulation regime, there has been a period of discussion and consultation within the sector. The comments from the industry were noted and taken into account when making decisions.

In addition, the regulatory process is highly transparent. Annual reports, results of performance comparisons and other documents are available to the public and can be accessed on NVE's website.

NVE also continuously works on system improvements. According to NVE, it is very important that the regulatory regime is dynamic enough to meet the evolving requirements of the industry. NVE commissioned reviews of the regulatory regime regularly and the model is under constant development.

10. SUMMARY AND CONCLUSIONS

The international shift from traditional cost of service regulatory regimes to incentive regulation and performance based regulation regimes since the 1990's was preceded by decades of academic literature pointing out that cost-based regimes create an implicit incentive for utilities to operate inefficiently. Economists observed that utilities could increase their profit by overinvesting in infrastructure. In addition, rate regulated utilities received no benefit from reducing their operating and maintenance costs since reducing costs resulted in a corresponding reduction in rates. Consequently, the primary imperative to operate more efficiently was in response to cost reductions imposed by the regulator. However, the literature suggested that regulators did not have the detailed operational information necessary to determine the minimum level of costs needed for a utility to operate efficiently. The utilities had better information but they had an incentive to overestimate the cost of operating efficiently. The higher the allowed costs the less risk there would be that unanticipated expenditures would cause the utility to earn a return on capital that was less than its allowed return.

The recommended response to this problem was to implement a regulatory regime with explicit efficiency incentives. Some regulators had observed that even a multi-year cost of service regime provided some degree of efficiency incentive. If the utility could reduce its cost of service, the regulatory lag provided an opportunity for it to earn an increased return on capital during the intervening years. However, this incentive was constrained because utilities often perceived a risk that underspending relative to forecast costs could undermine the credibility of their future cost forecasts.

The first incentive regimes were designed to make this implicit efficiency incentive more effective by implementing four innovations.

First, the incentive regimes explicitly recognized that utilities should be able to earn a premium over their standard allowed return on equity. This was part of the design and the companies "earned" the high return by becoming more efficient. While the saving would be retained by the company in the short run, after some period of time rates would be rebased and the savings would then flow through to customers.

Second, regulators recognized that there are limited opportunities to realize savings within a single year. Consequently, an effective incentive regime has to allow utilities to pursue productivity gains and retain the benefits of those efforts over an extended number of years in order to be an effective motivation to pursue productivity gains. To address this consideration, the initial regulatory incentive regimes were, at the core, multi-year cost of service regimes. Cost reviews continued to be used to set rates, but were less frequent. A period of five years between cost reviews has been a commonly used time frame for incentive regimes.

Third, regulators realized that costs tend to increase over time due to inflationary pressures on operating and maintenance expenses as well as on the average cost of the utilities capital assets. As a result, efficiency gains would typically result in a reduced rate of increase in costs, not an absolute decline in costs. The cost benchmark that the utility had to beat was therefore usually adjusted by some measure of inflation so that the regime would be sustainable over the multi-year term.

Fourth, the purpose of introducing incentive regulation was to motivate the utilities to pursue and achieve greater productivity improvements than were achieved under cost of service regulation and to flow some portion of the resulting savings through to customers. The underlying assumption was that the utilities had inefficiencies that would be squeezed out once the incentive regime was introduced. Hence, unless there were extraordinary cost pressures at the time incentive regulation was introduced, the utilities would not be challenged in keeping their cost increase below the rate of inflation. This consideration caused most regulators that implemented PBR regimes to include a productivity offset against the inflation factor so that rates or revenues would increase at less than the inflation rate. This productivity offset also served as a mechanism for ensuring that a share of the efficiency gains would flow through to consumers in the form of lower rates.

Over time, the initial incentive regimes tended to become more complicated as regulators recognized the need to provide incentives for behaviours other than cost reductions. In particular, it was quickly recognised that the easiest way to cut costs and increase profit was to reduce maintenance and defer capital expenditures. The resulting decline in reliability and other service standards was not always consistent with the goal of enhancing productivity. Consequently, a standard feature of the evolution of PBR regimes was the introduction of quality of service standards.

Regulators also observed that while a revenue cap provided an incentive for utilities to use their existing infrastructure more efficiently, a revenue cap was not appropriate in cases where major new capital investments were need to maintain or enhance the company's infrastructure. Consequently, some regulators adopted revenue cap models that included mechanism for increasing the allowed revenue to reflect major capital investments that could not be accommodated by the basic cap. This approach was more appropriate than adopting a price cap in situations where the cost driver did not relate to load or customer growth.

The cross-jurisdictional experience also shows that the complexity of the incentive regimes has also increases as the range of outcomes of interest expanded. Incentives have been introduced that relate to performance standards linked to a variety of specific policy objectives, including goals as energy conservation and the accommodation of renewable generation.

The latest evolution of the UK, Australian and Ontario regimes has been to adopt comprehensive outcomes-based regimes. These PBR regimes emphasize measuring success in terms of defined performance outcomes and require the utilities to demonstrate that they are building business plans based on consumer engagement and comprehensive planning. This approach gives the utilities more flexibility to determine what their specific goals should be, within a policy framework set out by the regulator, and informed by their customer engagement initiatives. It also allows the utilities to determine the best plan for achieving those goals. The utilities are then held accountable for achieving the results that they have proposed and the regulator has approved.

The international experience with PBR indicates that regulators are seeking to motivate utilities to be responsive to the outcomes that matter to their customers and to government policy. Customers care about price, but they also care about the reliability and quality of the electricity supply, as well as a wide range of customer service issues.

The expectations of customers appear to be increasing in parallel with the rising expectations of consumers generally. Consumers have every increasing expectations regarding the availability of information, convenience, and socially responsible products. Given the numerous concerns of consumers, it is not surprising that in attempting to reflect the complex dynamics of competitive markets, PBR regimes become increasingly complex as regulators keep adding incentives that relate to the various concerns of consumers and government as they are identified. Regulators have therefore moved forward from adopting a series of specific incentives to attempting to design comprehensive regimes that address all of the concerns through planning on a comprehensive basis.

The diversity of regimes also demonstrates that there is no single best practice that should guide the development of new PBR regimes. Rather it shows that in different circumstances the details of an effective regime need to be tailored to the specific objectives that are relevant to the regulator. At a high level, the experience with PBR indicates that regulatory best practice requires the implementation of incentives that reward the desired behaviours and only the desired behaviours. More specifically, best practices involve delinking revenue from cost for a long enough time to provide meaningful incentives and escalating revenues or rates in a manner that reflects the trend in efficient costs taking into account the desired behaviours for the utility. However, there is no universal best practice for selecting the specific features that need to be incorporated in a PBR regime within any specific jurisdiction.

The international experience to date also does not demonstrate whether the most recent PBR designs based on a consumer focus, defined performance outcomes and a flexible approach to how those outcomes should be achieved will prove to be practical and effective. The concept is promising but it is too early to determine clearly the success of these regimes. A related unknown is whether it is practical to implement this latest approach to PBR without using a more prescriptive version of PBR as a stepping-stone to an outcomes-based regime.

A challenge that may emerge in the future for regulators is the need to accommodate rate design changes within a PBR framework. The electricity industry is changing in ways that may make it necessary to adopt innovative rate designs in order to protect the utilities' revenue base and provide price signals that are efficient.

For example, some regulators are beginning to address issue related to revenue decoupling for distribution services that would price distribution services in a manner consistent with cost causality (e.g., charge customers based on demand or the capacity of the service connection rather than based on energy usage).

In addition, as new technologies make self-generation more economic, the risk that customers will begin to reduce or eliminate their reliance on the grid is an emerging concern. As this issue becomes more pressing, there may be a need for utilities to develop service and pricing strategies that respond to the competitive threat. The PBR regimes of the future are likely to have to be far more flexible than they have been in the past. Perhaps it is fortunate that if regulators are able to reduce their workload related to cost reviews for setting or rebasing rates, they will be able to focus more of their energy on emerging market and policy issues.

Appendix 1: Summary of Six Reviewed Jurisdictions

Table 1: Summary of Six Jurisdictions

Jurisdiction	Alberta	Australia	New York	Norway	Ontario	UK
Regulator	AUC	AER	NYPSC	NVE	OEB	OFGEM
Service	Distribution	Transmission (TranGrid)	Distribution (Consolidated Edison)	Transmission	Distribution	Transmission
Term	5 years	5 years	2 years	5 years	5 years	8 years
Form	Price Cap (I-X)	Revenue Cap (CPI-X)[82]	Rate Freeze	Revenue Cap (Yardstick)	Price Cap (I-X)	RIIO (Rev = Incentives + Innovation + Outputs)
Cost Benchmarking	No	Yes	No	Yes	Yes	Yes
Incentive Mechanisms	ECM[83]	EBSS[84] and CESS[85]	ESM[86]	No	No	Yes – Efficiency, Outputs, Innovation
Service Quality	Yes	Yes	Yes	Yes	Yes	Yes
Other Features			Decoupling Mechanism			

[82] Maximum allowed revenue is based on forecasts of the cost of service over the regulatory term

[83] Efficiency Carryover Mechanism

[84] Efficiency Benefit Sharing Scheme: Carry forward mechanism for opex with a 30/70 sharing between transmission providers and users

[85] Capital Expenditure Sharing Scheme: Forward capex allowance with 30/70 sharing

[86] Earning Sharing Mechanism

Appendix 2: PBR in Canada

Province	Company Name	Current	Historic
Alberta	Enmax	Price Cap Index	
	EPCOR, Fortis Alberta	Price Cap Index	
	Northwestern Utilities		Stairstep (1999-2002)
	EPCOR		Price Cap Index (2002-2005,terminated in 2003)
British Columbia	Fortis BC		Revenue Cap Hybrid (2006-2009, extended to 2011)
Manitoba			
New Brunswick			
Newfoundland			
Northwest Territories	Northland Utilities		Stairstep (2011-2013)
	Northland Utilities (Yellowknife)		Stairstep (2011-2013)
Nova Scotia			
Ontario	All Ontario distributors	Price Cap Index	
	All Ontario distributors		Price Cap Index (2000-2003)
	All Ontario distributors		Price Cap Index (2006-2009)
Prince Edward Island	Maritime Electric	Stairstep	
Québec			
Saskatchewan			
Yukon			

Appendix 3: PBR in US

This Appendix contains information about two recently released documents: "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives" and "Alternative Regulation for Evolving Utility Challenge."

The first document identifies and reviews alternative rate mechanisms in the United States. The second document is an updated survey that provides information about alternative regulatory policies in the United States.

Note that in the United States discussions of refinements to the traditional cost of service approach are commonly referred to as alternative rate mechanisms or alternative regulation. These mechanisms include, but are not limited to, PBR as is evident in the pages that follow.

Cover Page, Table of Contents and list of tables are provided below for both documents. The tables in the second document include state-by-state listings of various types of alternative regulation.

Figure 1: Cover Page

nrri

Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives

Ken Costello, Principal Researcher

National Regulatory Research Institute

Report No. 14-03

April 2014

8611 Second Avenue, Suite 2C
Silver Spring, MD 20910
Tel: 301-588-5385
www.nrri.org

Figure 2: Table of Contents

Table of Contents

List of Tables:

Figure 3: Cover Page

Edison Electric Institute

Alternative Regulation for Evolving Utility Challenges:

An Updated Survey

Prepared by:
Pacific Economics Group Research LLC

Mark Newton Lowry, PhD
Matthew Makos
Gretchen Waschbusch, MBA

Prepared for:
Edison Electric Institute

January 2013

Figure 4: Table of Contents

Table of Contents

List of Tables:

Appendix 4: Ontario

This Appendix contains additional information related to Ontario jurisdiction.

Table 2: Key Elements of various IR Generations

	1st	2nd	3rd	4th
Form	Price Cap (I-X)	Price Cap (I-X)	Price Cap (I-X)	Price Cap (I-X)
Term	3 years	up to 3 years	4 years (rebasing plus 3 years	5 years (rebasing plus 4 years)
Inflation Factor	Input Price Index	GDP IPI FDD	GDP IPI FDD	Composite
X factor	Varied with ROE	Same for all LDCs	Productivity component. Same for all LDCs The stretch factor component varies by distributor (different for each of the 3 cohorts[87])	Productivity component. Same for all LDCs The stretch factor component varies by distributor (different for each of the 5 cohorts[88])
Other Adjustment Factors	Z factor	Z factor	Z factor Incremental Capital module	Z factor Incremental Capital module
Sharing Benefits	ESM	Stretch Factor	Stretch Factor	Stretch Factor Case-by-case under the Custom IR option
Service Performance	Service quality requirements Service Quality Reporting Requirements	Service quality requirements Service Quality Reporting Requirements	Service quality requirements Service Quality Reporting Requirements	Service quality requirements Service Quality Reporting Requirements Performance Scorecard
Other Features	N/A	Off-ramps	Off-ramps (ROE dead band of +/- 300 basis points)	Off-ramps (ROE dead band of +/- 300 basis points)

[87] Group 1 : 0.2%; Group 2 : 0.4% ; Group 3 : 0.6%.

[88] Group I : 0.00%; Group II;0.15%,Group II; 0.30%, Group IV;0.45%, Group V ;0.60%.

RATE ADJUSTMENT PARAMETERS

Inflation Factor

The OEB adopted the 2-factor IPI methodology to track inflation and help mitigate volatility. The methodology included[89]:

> *(a) A labour sub-index comprised of the average weekly earnings for workers in Ontario4; and*
>
> *(b) A non-labour sub-index comprised of the Canada GDP-IPI (FDD) .5 The GDP-IPI is the federal government's featured index of inflation in the domestic economy's final goods and services. It covers inflation in the prices of capital equipment used by industry as well as inflation in consumer product prices. This broad coverage makes it stable and, for a macroeconomic measure, reasonably reflective of inflation in the prices of distributor inputs.*

Component weights are 30% for labour and 70% for non-labour, based on estimates of distributors cost shares.

Table 3: Sample Average OM&A Cost Shares

Distributor Segment	Average Capital Cost Share	Average OM&A Cost Share	Labour component of OM&A (70% assumption9)
33 Small (total cost < $10 million)	41.05%	58.95%	41.27%
28 Medium (total cost $10 < $40 million)	56.55%	43.45%	30.42%
10 Large (total cost $40 - $300 million)	60.71%	39.29%	27.50%
2 Very Large (total cost >$300 million)	62.52%	37.48%	26.24%

Source: EB-2010-0379, Report of the Board, December 4, 2013

The Board performs the calculation of the 2-factor IPI using the year-over-year change in the GDP-IPI (FDD) and the AWE- All Employees-Ontario. The OEB reports the inflation factor ones a year.

[89] EB-2010-0379, Report of the Board, December 4, 2013.

X-Factor Components

Productivity Factor

The determination of the productivity factor relies on the index-based approach. The productivity factor remains in effect until the next rebasing. In order to isolate OPA CDM program costs from TFP analysis, the Board requires distributor's RRR balances corrections.

The Board determined the value for the productivity factor for Price Cap IR to be zero. In the Board's view this value "reflects a reasonable balance of the estimated productivity trend in the sector over the last 10 years and a value that is reasonable to project into the future as an on-going external industry benchmark which all distributors should be expected to achieve[90]."

Stretch Factor

The OEB believes that stretch factors are required and have an important role in IR plans since they promote, recognize and reward distributor for efficiency improvements relative to the expected sector productivity trend. The stretch factor assignments are made on the basis of total cost benchmarking evaluations, and are revised annually. Distributors are assigned to one of five groups with stretch factors, based on their efficiency. The OEB determined that the stretch factor values range from 0% to 0.6%.

Table 4: Demarcation Points and Stretch Factor Values

Group	Demarcation Points for Relative Cost Performance	Stretch Factor
I	Actual costs are 25% or more below predicted costs	0.00%
II	Actual costs are 10% to 255 below predicted costs	0.15%
III	Actual costs are within +/- 10% of predicted costs	0.30%
IV	Actual costs are 10% to 25% above predicted costs	0.45%
V	Actual costs are 25% or more above predicted costs	0.60%

Source: EB-2010-0379, Report of the Board, December 4, 2013

[90] EB-2010-0379, Report of the Board, December 4, 2013.

Benchmarking

The OEB uses PEG's econometric model for benchmarking distributor cost performance. The model is used to predict the total cost of each distributor, and the distributor's actual total costs are compared to the econometric prediction. PEG's model uses a well-established estimation procedure, does not rely on peer grouping, and does not assume constant return to scale. It includes factors beyond management control such as:

- the number of customers served
- kWh deliveries
- system capacity peak demand
- average circuit km of line
- share of customers served that were added over the last 10 years

KEY ENHANCEMENTS OF THE 3RD GENERATION IR

1. **Productivity factor stretch factor based on benchmarking results :** The OEB allocated distributors across three efficiency "cohorts"[91]:
   - 50% of distributors were allocated to the middle cohort and assigned a stretch factor of 0.4%.
   - 25% were allocated to the most efficient cohort were assigned a stretch factor of 0.2%,
   - 25% were allocated to the least efficient cohort and were assigned a stretch factor of 0.6%.
2. **Incremental Capital Module (ICM) :** This change was made in response to distributor claims regarding the increased need for capital investments caused by aging infrastructure and the obligation to connect new renewable generation. Under the ICM, distributors may apply during the term of their rate plan to recover costs associated with incremental capital requirements. The criteria of materiality,

[91] Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008.

need and prudence were to be reviewed in detail for each application. Originally the OEB was quite strict in its review of ICM applications and several early applications were denied. Over time more ICM applications were approved.

OBJECTIVES OF RRFE AND ENHANCEMENTS OF 4TH GENERATION IR

The OEB issued its report, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE) on October 18, 2012, and the new framework is being implemented for 2014 rates.

The OEB has positioned the RRFE rate-setting framework within an overall outcomes-based approach. The objectives for RRFE are articulated in terms of four specific outcomes:

> *The renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. The Board believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. The Board has concluded that the following outcomes are appropriate for the distributors:*
>
> - *Customer Focus: services are provided in a manner that responds to identified customer preferences;*
> - *Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;*
> - *Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and*
> - *Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.*[92]

In developing 4th Generation IR, the OEB has refined the 3rd Generation IR in three key areas:

---

92 Ontario Energy Board, *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: a Performance-Based Approach*, EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043, EB-2011-0004, October 18, 2012, p. 2.

- The total term has been extended from four years to five years.
- A more industry-specific inflation factor: an Ontario based labour cost inflator and a Canadian inflator for non-labour costs.
- Five efficiency cohorts (up from three in 3rd Generation IR) and a larger spread of efficiency factors, from 0% to 0.6% (compared to the range of 0.2%-0.6% in 3rd Generation IR).

The OEB also introduced two new elements within the RRFE:

- Three rate-setting options considering the differences in LDCs
- Performance monitoring through a scorecard approach

These new elements are discussed in the next sections.

COMPONENTS OF THE THREE METHODS UNDER 4TH GENERATION IR

During the consultation, stakeholders emphasized that there were differences amongst the 77 electricity distributors in terms of their capital needs and growth levels. The OEB addressed these varying needs by introducing a menu of three rate-setting methods: 4th Generation IR is a modified version of the previous framework (3rd Generation IR); Annual IR is a simpler option, and Custom IR is a more complex option. The expectation is that a distributor will choose the option that is most suitable for its circumstances and needs. The following table provides an over-view of key elements of the three rate-setting IR models:[93]

[93] RRFE Report, page 13.

Rate-Setting Overview - Elements of Three Methods

	4th Generation	Custom IR	Annual IR Index
Setting of Rates			
"Going in" Rates	Determined in single forward test-year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form	Price Cap Index	Custom Index	Price Cap Index
Coverage	Comprehensive (ie. Capital and OM&A)		
Annual Adj Mechanism			
Inflation	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distribuors' forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; (3) benchmarking to assess the reasonableness of the distribuor's forecasts	Composite Index
Productivity	Peer Group X-factors comprised of (1) Industry TFP growth potential (2) a stretch factor		Based on 4th generaion IR X-factors
Role of Benchmarking	To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits	Productivity factor		
	Stretch factor	Case-by-case	Highest 4th generation IR stretch factor
Term	5 years (rebasing plus 4 years)	Minimum term of 5 years	No fixed term
Incremental Capital Module	On application	n/a	n/a
Treatment of Unforeseen events	As set out in 3rd generation		
Deferral and Variance	Status Quo	Stats Quo, plus as needed to track capital spending against plan	Disposition limited to Group 1; Separate application for Group 2
Performance Reporting and Monitoring	A regulatory review may be initiated if a distributor's annual reports show performance outside of the +/-300 basis points earnings dead band or if performance erodes to unacceptable levels		

Several distributors have applied under the Custom IR option, including Hydro One Distribution, Toronto Hydro and Horizon Utilities. Enbridge Gas Distribution applied for a similar rate framework, and the OEB approved the application with modifications.[94]

FOCUS ON PERFORMANCE MEASUREMENT

The scorecard includes the five most recent years of available data for each performance measure, which will allow meaningful comparison over the years and

94 *Decision with Reasons*, EB-2012-0459, Enbridge Gas Distribution Inc. July 17, 2014.

across distributors. The results will be reported annually, and the OEB will take corrective action if and when required related to utilities performance.

The following table sets out the performance outcomes, the performance categories for each outcome, and the specific measures:

Performance Outcomes	Performance Categories	Performance Measures
Customer Focus Services are provided in a manner that responds to identified customer preferences	Service Quality	New residential services connected on time
		Scheduled appointments met on time
		Telephone calls answered on time
	Customer Satisfaction	First contact resolution
		Billing accuracy
		Customer satisfaction survey results
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public safety (measure to be determined)
	System Reliability	Average number of hours that power to a customer is interrupted
		Average number of times that power to a customer is interrupted
	Asset Management	Distribution system plan implementation progress
	Cost Control	Efficiency Assessment Total cost per customer
		Total cost per km of line
Public Policy Responsiveness Distributors deliver on obligations mandated by government (eg. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board)	Conservation and Demand Management	Net annual peak demand savings (percent of target achieved)
		Net cumulative energy savings (percent of target achieved)
	Connection of Renewable Generation	Renewable generation connection impact assessments completed on time
		New micro-embedded generation facilities connected on time

Financial Performance Financial viability is maintained and savings from operational effectiveness are sustainable	Financial Ratios	Liquidity: Current ratio (Current assets/ current liabilities)	
		Leverage: Total debt (includes short-term and long-term debt) to equity ratio	
		Profitability: Regulated Return on Equity	Deemed (included in rates)
			Achieved

Most of the measures included in the scorecard are already in place and are part of the current reporting requirements. For each of these, a target performance has been identified. Five new measures were introduced that focus on customer experience and effective planning. A performance target has not been established yet for all of these new measures. No financial penalties or incentives have been implemented, but these may be considered in the future. In keeping with its heightened focus on customers, the OEB has developed plain language descriptions for each of the measures.

The first set of annual scorecards has now been filed and posted on the OEB's website.[95]

COMPLEMENTARY POLICY DEVELOPMENT

In the last few years Ontario has witnessed significant changes in energy policies, essentially driven by environmental regulations through Green Energy Act legislation. In addition, considerable capital investments were required for system reliability of the distribution and transmission networks. These developments result in increased rates to customers and regulation need to demonstrate the value created for customers.

To complement the 4th generation IR model, the RRFE has also established a framework within which further policy development work is ongoing in the following areas:

- revenue decoupling (EB-2012-0410)
- investment planning (EB-2010-0377)
- performance measurement (EB-2010-0379)

95 Electricity Distributor Scorecards.

- smart grid (EB-2011-0004)
- regional planning (EB-2011-0043)
- capital Investment funding (EB-2014-0219)

KEY REFERENCES

Ontario Energy Board, Report of the Board: Renewed Regulatory Framework for Electricity Distributors: a Performance-Based Approach. (2012, October 18). Retrieved November 17, 2014 from http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf

Supplemental Report of the Board on 3rd Generation

Incentive Regulation for Ontario's Electricity Distributors, EB-2007-0673. (2008, September 17). Retrieved November 17, 2014 from http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2007-0673/Supp_Report_3rdGen_20080917.pdf

Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. (2006, December 20,). Retrieved November 17, 2014 from http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0088/report_of_the_board_201206.pdf

Decision with Reasons, RP-1999-0034. (200, January 18). Retrieved November 17, 2014 from http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/dec.pdf

OTHER REFERENCES

Report on the Ontario Energy Board Natural Gas Forum, Natural Gas Regulation in Ontario: A Renewed Policy Framework. (2005, March 30). Retrieved November 17, 2014 from http://www.ontarioenergyboard.ca/documents/consultation_ontariogasmarket_report_300305.pdf

Decision with Reasons, EB-2012-0459. (2014, July 17). Retrieved November 17 from http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/443614/view/dec_with%20reasons_EGDI_20140717.PDF

Performance Measurement for Electricity Distributors: A Scorecard Approach, EB-2010-0379. (2014, March 5). Retrieved November 17, 2014 from http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0379/Report_of_the_Board_Scorecard_20140305.pdf

Incentive Regulation (EB-2007-0673). Retrieved November 17, 2014 from http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/3rd+Generation+Incentive+Regulation

Ontario Energy Board Draft Policy on Performance Based Regulation. (1998, October 2). Retrieved November 17, 2014 from http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/Draft_Policy.PDF

Appendix 5: Alberta

This Appendix contains additional information related to Alberta jurisdiction.

Table 5: Alberta PBR Regimes

	ENMAX (2007-2014)	1st Generation PBR (2013-2018)
Form	Price Cap (I-X)	Price Cap (I-X)
Term	7 years	5 years
Inflation Factor	Electric Utility Construction Price Index (EUCPI) and Average Hourly Earnings	Alberta Weekly Earnings Index (AWE)
X factor	X-Factor of 1.20% based on a TFP growth rate of 0.80% plus a stretch factor of 0.40%	X-Factor of 1.16% based on a TFP growth rate of 0.96% plus a stretch factor of 0.2%
Other Adjustment Factors	G factor: adjustment to the transmission revenue requirement based on transmission growth Z factor with a materiality threshold of $1 million	Capital Tracker, Z Factor and Y Factor
Sharing Benefits	ESM (an asymmetrical earnings sharing with only gains shared with customers)	ECM (utilities are allowed to carry-over up to 0.5 of earnings two years after the end to PBR plan term)
Service Performance	Service Quality Reporting Requirements	Service Quality Reporting Requirements AUC has the power to apply administrative penalties up to $1 million
Other Features	Re-openers (specific reopeners related to service quality, accounting standards, expansion of service territory and return)	Re-openers (materiality threshold: 500 basis points above or below the approved ROE in a single year, or 300 basis points over a period to two consecutive years)

HIGHLIGHTS OF ENMAX FBR

The AUC approved a five-year FBR plan for ENMAX effective from January 1, 2007.

ENMAX Experience

ENMAX stated that a number of efficiency improvements and cost-minimising measures were realized as a result of its transition to a regulatory regime with stronger efficiency incentives. ENMAX indicated that it would not have undertaken these productivity initiatives under a traditional cost of service regulation.[1]

Furthermore, in filed by Russ Bell before the British Columbia Utilities Commission indicates that ENMAX Distribution was able to accommodate load growth within its service territory (i.e. the City of Calgary) while under FBR, and still show growth in returns. With respect to ENMAX Transmission Division, the evidence showed low returns in 2011 and 2012 that were subject to a reopener application. According to the evidence, the low returns as reported were a result of how ENMAX accounts for its capital compared to its G-Factor revenue. Such a mismatch resulted in lower returns. The evidence indicated that during the term of the ENMAX FBR, there was no reported degradation in service quality.[1]

This FBR plan included:

- An I-Factor based on changes in Electric Utility Construction Price Index (EUCPI) and Average Hourly Earnings.
- An X-Factor of 1.20% which reflected total factor productivity growth rate of 0.80% plus a stretch factor of 0.40%.
- An exogenous factor (Z-Factor) adjustment mechanism with a materiality limit of $1.0 million.
- An allowance for specific flow through items outside the control of the utility
- Specific reopeners related to service quality, accounting standards, expansion of service territory and return on equity.
- An asymmetrical earnings sharing with only gains shared with customers; losses were not shared.

DETAILS OF THE ALBERTA'S FIRST GENERATION PBR MODEL

The Alberta PBR model is a price cap for electricity distribution companies. The annual rate for electric distribution companies are adjusted as follows:

$$R_t = BR_{t-1} (I + (1-X)) +/- Z +/- K +/- Y$$

Where:

R_t	=	upcoming year's rates for each class
BR_{t-1}	=	current year's base rates for each class
I	=	inflation factor
X	=	productivity factor
Z	=	exogenous adjustments
Y	=	flow-through items, collected through Y factor rate adjustments
K	=	capital trackers collected through K factor rate adjustments

The model has the following parameters which are discussed in brief below:

1. Base Rates
2. I Factor
3. X Factor
4. Z Factor
5. Y Factor
6. Capital Tracker (K-Factor)
7. Re-openers and off-ramps
8. Efficiency Carryover mechanism (ECM)
9. Term

Base Rates

Base rates are established on a cost of service basis. The AUC considered two approaches for determining base rates. In its Decision 2012-237 the AUC approved the use of most recent approved rates (i.e. 2012) as base rates.

I-Factor

The AUC approved a composite inflation factor in the PBR plans for electricity distribution companies in Alberta. As described in the PBR decision, the adopted inflation factor is a weighted average of average weekly earnings (“AWE”) index and Alberta CPI. The first component of the composite I-Factor for the upcoming year is the actual Alberta AWE for the previous July through June period published by Statistics Canada, and the second component is the actual Alberta CPI for the previous July through June period published by Statistics Canada. The selection of the start and ending months for the 12-month period reflects the latest published Statistics Canada data prior to September. The AUC determined that utilities use a 55:45 ratio of labour to non-labour expenditures for calculating the I factor.

X- Factor

The AUC approved an X factor based on the long-term rate of productivity growth in the industry. The AUC adopted NERA’s proposed long-term industry TFP of 0.96 per cent as a basis for determining the X factors. Additionally, the AUC approved a stretch factor of 0.2 per cent. As a result, the AUC approved a total X factor of 1.16 per cent, inclusive of a stretch factor, for all utilities with the exception of ENMAX.

There were two studies to determine the TFP. In the first study NERA calculated a TFP of 0.96 percent. This study was based on the analysis of the population of 72 U.S. electric utilities and combination of electric/gas companies. A second study was conducted by PEG on behalf of CCA. The AUC found that NERA’s study was more objective and transparent compared to PEG’s analysis. The AUC accepted NERA’s methodology and found that a TFP estimate of 0.96 per cent was a reasonable starting point for setting an X factor for Alberta utilities.

The PBR plans for Alberta companies also included a stretch factor. The Office of the Utilities Consumer Advocate’s (UCA) experts suggested that stretch factors should lie in the range between 0.2 and 0.6, and PEG experts recommended the stretch factors of between 0.19 and 0.5. The AUC took a conservative approach having in mind that companies would face uncertainties associated with new regulatory framework and approved a stretch factor of 0.2 per cent for the duration of PBR period.

Z-Factor

Alberta PBR plans include a Z factor to provide for exogenous events. This mechanism allows for adjustment in case of events outside of the control of the company having a significant impact on company finances, and for which the company has no other reasonable opportunity to recover the costs within the PBR formula.

As outlined the PBR decision the AUC adopted the following five criteria for evaluating whether the impact of an exogenous event would qualify for a Z factor adjustment: [96]

1. *The impact must be attributable to some event outside management's control;*
2. *The impact of the event must be material. It must have significant influence on the operation of the utility otherwise the impact should be expensed or recognized as income, in the normal course of business;*
3. *The impact of the event should not have a significant influence on the inflation factor in the PBR formulas;*
4. *All costs claimed as an exogenous adjustment must be prudently incurred; and*
5. *The impact of the event was unforeseen.*

The AUC determined that all five criteria must be satisfied for a cost item would qualify for Z factor treatment. Additionally, the AUC established the materiality threshold as the dollar value of 40 basis points change to ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which base rates were established (2012).

---

96 AUC Decision 2012-237, page 110.

Capital Tracker (K-Factor)

The capital tracker mechanism provides supplemental capital funding. This mechanism is intended for situations where the required capital replacement project cannot be expected to be recovered through the I-X mechanism.

The AUC set out the following criteria which is described in the PBR decision for the inclusion of companies selected capital projects for capital tracking:[97]

1. *The project must be outside of the normal course of the company's ongoing operations.*
2. *Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.*
3. *The project must have a material effect on the company's finances*

Y- Factor

The AUC adopted a Y factor to recover costs that do not qualify for capital tracker treatment or Z treatment.

The AUC established the following six criteria outlined in the PBR decision for evaluating whether a cost will qualify for a Y factor treatment:[98]

1. *The costs must be attributable to events outside management's control.*
2. *The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.*
3. *The costs should not have a significant influence on the inflation factor in the PBR formulas.*
4. *The costs must be prudently incurred.*
5. *All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.*

---

[97] AUC Decision 2012-237, page 126.

[98] AUC Decision 2012-237, page 135.

The AUC determined that the five criteria must be satisfied so as a cost would qualify for Y factor treatment. It approved that the materiality threshold of 40 basis points change in ROE established for Z factors would also apply to Y factors.

The AUC approved the following accounts for flow through treatment:

- Alberta Electric System Operator (AESO) Flow Through items
- Farm Transmission Costs
- Accounts that are a result of Commission Directions
- AUC Assessment Fees
- Effects of regulatory Decisions
- Customer portion of Hearing Costs, but not the company portion
- AUC tariff billing and load settlement initiatives
- UCA assessment fees
- Municipal fees
- Load balancing
- Weather deferral
- Production abandonment
- Income tax impacts other than tax rate changes

Re-openers and off-ramps

AUC did not adopt automatic reopeners, but any party, including the AUC may file an application to re-open, if there is enough evidence that there is a need for revision or modification. The AUC found that an earned ROE that is 500 basis points above or below the approved ROE in a single year, or 300 basis points for two consecutive years, is sufficient to warrant consideration of a re-opening and review of a PBR plan. The material contraction and expansion of customers or service territories is also an event that may qualify for a re-opening and review of a PBR plan. Furthermore, an application to the AUC for a re-opening can be filed for matters related to a change in law or a regulatory direction that cannot be dealt with through Z-factor treatment or other mechanisms. An applicant may also bring a re-opener application before the AUC for consideration in case of a material event that is completely unforeseen and cannot be accommodated within the parameters of the PBR plan.

Efficiency Carryover Mechanism (ECM)

The AUC approved an efficiency carry-over mechanism (ECM). This is an innovative mechanism which provides an incentive for utilities to continue to make cost saving investments near the end of the PBR term to the extent that utilities are permitted to continue to benefit from any efficiency gains beyond the PBR plan term. The AUC considered it reasonable 0.5 per cent of the earnings as the upper limit of the earnings that can be carried over. The AUC approved an ROE ECM that would apply for 2 years after the end of the PBR plan. For the purposes of calculating the amount of the ECM, Alberta's utilities are required to compute the actual ROE in the same way as the ROE reported in their annual AUC Rule 005 filings.

Term

The length of Alberta's PBR plans is 5 years. In the AUC's view, five-year fixed period for all PBR plans was acceptable, since PBR plans contained many new components. The AUC noted that it chose this PBR plan length recognizing that some of the elements approved in the PBR plans are novel and such a term is consistent with the typical term for PBR plans in North America. The AUC found that a shorter term tends to blunt the incentives for companies to identify and implement productivity improvements, noting that the inclusion of an efficiency carry-over mechanism mitigates this effect. The AUC did not approve the recommendation for a mid-term review half-way through the PBR term because doing so effectively shortens the term to two years which, in the AUC's view, eliminates the benefits achieved from lengthening the regulatory lag.

Earning Sharing Mechanism (ESM)

The AUC did not include earning sharing mechanism in the PBR plans. The AUC agreed with EPCOR and AltaGas Utilities Inc.'s experts that PBR plans with an ESM provide weaker incentives for efficiency gains, in part because costs and rates are no longer completely decoupled.[99] The AUC shared the concerns raised by EPCOR's expert with regard to ESM:

> *And when I say that earnings sharing has problems, it has problems I think on both sides. I don't think, as I mentioned in my rebuttal testimony, it brings forth the best behaviour on the part of regulators or the firms they regulate. I think that there are incentives for cost misreporting; cost shifting; the incentives are blunted with regard to managerial effort, and the reason for that is that the firm bears the entire costs of its effort at reducing costs but only retains a share of the fruits from those efforts.* [100]

The AUC agreed with EPCOR, AltaGas, ENMAX and Industrial Power Consumers Association of Alberta (IPCAA) that increased scrutiny on an annual basis would be required for earnings sharing and would result in a greater regulatory burden.[101]

Service Quality

Alberta utilities are required to keep their current levels of service quality throughout the PBR period. The AUC monitors service quality performance through AUC Rule 002 which sets out service quality reporting requirements. This rule requires electric utilities to file quarterly and annual performance reports. The AUC has the authority, under both the Electric Utilities Act and the Gas Utilities Act, to make and enforce rules respecting service quality standards, and to impose penalties on regulated utilities.

The AUC sets out well-defined service quality measures, targets and non-compliance penalties. The AUC has the power in law to fine companies up to $1 million a day for each contravention, the power to set utility terms and conditions, and the power to force a utility to give up any profit it may have gained from breaking the rules. [102] In the PBR decision the AUC found that it would be relying on AUC Rule 002 along with administrative penalties as set forth in law to ensure that service quality is maintained. In its Decision 2012-237 the AUC specifically rejected any performance bonus for companies in the event of exceeding the service quality targets.

---

99 AUC Decision 2012-237, page 177.

100 Ibid.

101 Ibid.

102 AUC's webpage on Performance-Based Regulation.

As earlier indicated in the PBR decision the AUC approved the inclusion of re-openers and off-ramps as part of the PBR plans. It should be noted that in the PBR decision the AUC did not accept a proposal to re-open the PBR plan due to an event of service-quality degradation[103].

In the PBR decision the AUC set out directions on a Rule 002 consultation to address the following issues: annual review meetings, additional service quality metrics, setting targets and penalties, asset management reporting and line losses.

Pursuant to AUC directions, consultations took place in the last quarter of 2012 and amendments to Rule 002 were approved in December 2012. This is a continuous process and further amendments to the rule were approved in December 2013.[104]

PBR IMPLEMENTATION

As earlier indicated the AUC issued the PBR decision in September 2012, following a generic proceeding that involved both electric and gas distribution companies. The transmission PBR models were scheduled to be addressed at a later date.

In accordance with the PBR decision, electricity utilities were required to file individual applications for their respective rates, capital trackers and other specific approvals. The first year was challenging and the PBR framework took approximately 30 months. This was expected as it was a transition from cost of service to PBR. The expected timeframe for annual updates during the PBR term was as follows[105]:

March: Submission of capital tracker applications

May 1: AUC Rule 005 (Financial and Operational Results) annual filings

Sept 10: Annual PBR rate adjustment filings

Jan 1: Effective date for approved rates

In its PBR decision the AUC provided an opportunity for individual companies to file its request for capital trackers. Considering the timelines for rate implementation effective

[103] AUC decision 2013 – 237 page 205.

[104] AUC's webpage on Rules 002 and 003 - Service quality and reliability.

[105] AUC Decision 2012-237, page 213.

as of January 1, 2013, the AUC approved capital tracker amounts equal to 60% of the applied amounts for capital trackers for interim rates. These amounts would be trued up based on the AUC's decisions as part of capital tracker application proceedings[106].

Individual electricity distributors filed detailed business cases for their capital tracker requirements. On December 6, 2013, the AUC issued Decision 2013-435 in respect of 2013 Capital Tracker Applications.

The AUC and the stakeholders recognized the challenges in the implementation of the capital tracker mechanism. The Capital tracker applications involved very detailed understanding and testing of individual utilities' proposals. Considering that was a first experience of capital tracker the AUC was diligent in providing a comprehensive issues list for determining the capital tracker treatment approvals. The issues dealt included:[107]

- *Double counting*
- *Historical spending levels*
- *Investment shortfall analysis*
- *Importance of project in providing service*
- *Engineering studies*
- *Historical maintenance and replacement practices*
- *Asset replacement*
- *Driven by external party*
- *Ordinarily funded within the formula*
- *Materiality threshold*
- *Grouping*
- *Assessing the reasonableness of capital forecasts*
- *Determination of invested capital and the calculation of the K factor*
- *Portion of project costs that are to be covered through a capital tracker*
- *Mid-year convention considerations*

The above scrutiny of evidence closely resembles how cost of service applications were reviewed. The expectation is that the regulator, the utilities and the interveners would become more familiar from this first review and the future reviews of capital trackers and other adjustments would become more efficient.

---

106 AUC Decision 2013-435 (December 6, 2013).

107 AUC Decision 2013-435 (December 6, 2013) page 237.

KEY REFERENCES

Decision 2012-237, Rate Regulation Initiative: Distribution Performance-Based Regulation. (2012, September 12). Retrieved November 6, 2014, from http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf

Decision 2013-435, Distribution Performance-Based Regulation 2013 Capital Tracker Applications. (2013, December 6). Retrieved November 6, 2014, from http://www.auc.ab.ca/applications/decisions/Decisions/2013/2013-435.pdf

OTHER REFERENCES

Grieve, W. (2014, July 1). 2014 CAMPUT Energy Regulation Courses. Retrieved November 6, 2014, from http://www.camput.org/wp-content/uploads/2013/08/Performance-Based-Regulation-Willie-Grieve.pdf

Performance-Based Regulation for Alberta Brochure. (n.d.). Retrieved November 6, 2014, from http://www.auc.ab.ca/news-room/brochures/Documents/PBR_brochure.pdf

Letter, Rate Regulation Initiative Round Table. (2010, February 26). Retrieved November 6, 2014, from http://www.auc.ab.ca/items-of-interest/Rate-Regulation-Initiative/Documents/2010-03-16%20-%20Rate%20Regulation%20Initiative%20Roundtable.pdf

Bulletin 2010-20, Regulated Rate Initiative: PBR Principles. (2010, July 15). Retrieved November 6, 2014, from http://www.auc.ab.ca/news-room/bulletins/Bulletins/2010/Bulletin 2010-20.pdf

Performance-Based Ratemaking Revenue Requirements 2014-2018. (2013, June 18). Retrieved November 6, 2014, from http://www.bcuc.com/Documents/Proceedings/2013/DOC_34888_B-1-1_FEI-2014-18-PBR-Application-Vol-2.pdf

Performance-Based Ratemaking Revenue Requirements 2014-2018 Exibit B2-26. (n.d.). Retrieved December 18, 2013, from http://www.bcuc.com/Documents/Proceedings/2014/DOC_41047_B2-26_FBC-Witness-Aid-to-RBell-BCPSO.pdf

FortisBC Energy Performance Based Ratemaking Revenue Requirements 2014-2018 Exibit C5-6. (2013, December 18). Retrieved November 17, 2014, from http://www.bcuc.com/Documents/Proceedings/2013/DOC_39039_C5-6_BCPSO_Evidence_Bell-Testimony.pdf

Appendix 6: New York (Consolidated Edison)

This Appendix contains the information relevant to New York jurisdiction.

Table 6: Overview of Consolidated Edison's Rate Plans

	1992- 1995	1995-1997	1997-2000	2000-2005	2005-2008	2010-2013	2014-2015
Form	Stairsteps	Revenue per customer cup	Rate freeze	Rate freeze	Stairsteps	Stairsteps	Rate freeze
Term	3 years	3 years	3 years	5 years	3 years	3 years	2 years
Inflation Factor							
X factor							
Other Adjustment Factors							
Sharing Benefits	ESM	ESM	ESM	ESM	ESM	ESM	ESM
Service Performance	Yes Penalties Scheme	Yes Penalties Scheme	Yes Penalties Scheme	Yes Penalties Scheme	Yes Penalties Scheme	Yes Penalties Scheme	Yes Penalties Scheme
Other Features	ERAM	ERAM	No	No	No	Decoupling Mechanism	Decoupling Mechanism

Electric Revenue Adjustment Mechanism (ERAM)

(1992-1995): According to Con Edison's 1991 Annual Report "the settlement includes a significant new rate-making concept known as the electric revenue adjustment mechanism, or ERAM. The purpose of the ERAM is to reduce the linkage between customers' energy consumption and Company profits. Under the ERAM the Company's rates will be based on annual forecasts of electric sales and sales revenues with return to or recovery from customers of any sufficiency or deficiencies from the forecast for the prior rate year. Introduction of the ERAM will remove from Company earnings the effects of year-to-year weather variations and variations of sales from forecasts due to economic conditions. The ERAM will also take into account cost increases in the second and third rate years for capacity costs associated with IPPs, amortization of Enlightened Energy costs, property taxes, and labor costs, including postretirement benefits other than pensions. The ERAM will also take into account projected increases in rate base and increased interest expense resulting from new debt issues."

(1995-1997): The ERAM that was established in the previous period continued, but modified.

Decoupling Mechanism

The NYPSC's order[108] issued on April 20, 2007 required utilities to file proposals for true-up based decoupling mechanisms. True-ups occur annually and include net lost revenues due to the more efficient energy use.

Earning Sharing Mechanism

(1992-1995): Earnings above an 11.75% return on common equity in the first year, and above 11.85 % in the second or third year are to be shared with customers (50/50).

(1995-1997): The company shares 50/50 with customers if it earns between 50 and 150 basis points above the allowed ROE. If the company earns more than 150 basis points above the allowed ROE, 75% of earnings go to customers.

(1997-2000): Under the agreement, the earnings in excess of a 12.9 % return on common equity are to be shared equally between customers and stockholders (50/50).

(2000-2005): Under the agreement, the earnings in excess of 11.75 % return on equity are to be shared between customers and stockholders (65/35).

(2005-2008): 50/50 earnings sharing apply in the event of an earned equity return between 11.4% and 13.0 %. The earnings in excess of 13 % are shared 75/25.

---

108 Order Requiring Proposals for Revenue Decoupling Mechanisms, April 20, 2007.

(2010-2013): 50/50 earnings sharing apply in the event of an earned equity return between 11.15% and 12.149 %. Earnings above 12.15% and up to 13.149% is shared 75/25, and 90% of any earnings above 13.15% is deferred for the benefit of customers and the remaining 10% is retained by Consolidated Edison.

(2014-2015): 50/50 earnings sharing apply if ROE > 9.8% but ROE < 10.45%; 75/25 earnings sharing apply if ROE >= 10.45%, but ROE<=10.95% ; 90/10 earnings sharing apply if ROE > 10.95%.

SERVICE PERFORMANCE

Table 7: Penalty Structure and Exclusions within the RMP

Metric	Revenue Adjustment (million)
SAIFI	$5
CAIDI	$5
Number of Network Outages per 1000 Customers	$4
Number of Feeder Open-Automatics	$1
Average Network Outage Duration	$5
Major Outages	$30[109]
Restoration	No revenue adjustment
Remote Monitoring System	$50[110]
Program Standards	$12
Intrusion Detection System	$2

109 A revenue adjustment of $5 million, $10 million, or $15 million (depending on outage duration) for each network major outage event and $10 million for each radial event; an annual cap of $30 million for up to three major outage events.

110 $10 million per network, with an annual cap of $50 million.

Table 8: Customer Service Performance Mechanism (Threshold Level and Revenue Adjustment)

Indicator	Maximum Revenue Adjustment	Threshold Level	Revenue Adjustment
Commission Complaints	$ 9 million	</ = 2.5 >2.5-</=2.7 >2.7-</=2.9 >2.9	N/A $2,000,000 $5,000,000 $9,000,000
Customer Satisfaction Surveys	$18 million		
Customer Survey of Emergency Calls (electric only)		>/=79.0 <79.0->/=76.0 <76.0->/=73.0 <73.0	N/A $1,500,000 $3,000,000 $6,000,000
Customer Satisfaction Survey of Phone Center Callers (non-emergency)		>/=82.0 <82.0->/=80.0 <80.0->/=78.0 <78.0	N/A $1,500,000 $3,000,000 $6,000,000
Customer Satisfaction Survey of Service Center Visitors		>/=84.0 <84.0->/=82.0 <82.0->/=80.0 <80.0	N/A $1,500,000 $3,000,000 $6,000,000
Outage Notification	$ 8 million	Communication Timeliness Communication Content	$300,000 per communication activity
Call Answer Rate	$ 5 million	>/=56.0% <56%->/=55.5% <55.5%->=55.0% <55.0%->/=54.5% <54.5%	N/A $1,000,000 $2,000,000 $4,000,000 $5,000,000

Source: Case 09-E-0428

KEY REFERENCES

CASE 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. (2014, April 25). Retrieved November 6, 2014, from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9CF883CB-E8F1-4887-B218-99DC329DB311}

Newton Lowry, M., Makos, M., & Waschusch, G. (2013, January 1). Alternative Regulation for Evolving Utility Challenges: An Updated Survey. Retrieved November 6, 2014, from http://www.eei.org/issuesandpolicy/stateregulation/Documents/innovative_regulation_survey.pdf

Order, Electric, Gas and Steam Rate Plans in Accord with Joint Proposal. (2014, February 21). Retrieved November 6, 2014, from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1714A09D-088F-4343-BF91-8DEA3685A614}

OTHER REFERENCES

Brilling, J. (n.d.). CASE 09-E-0428, Order Regarding Reliability Performance Mechanism. Retrieved September 14, 2012, from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F4797A12-4B20-4AF8-B3E6-AFC3D76E0DCB}

2012 Electric Reliability Performance Report. (2013, June 13). Retrieved November 6, 2014, from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={8D094296-7013-425D-9287-043D8860D0CF}

Report on 2013 Performance under Electric Service Reliability Performance Mechanism. (2014, April 1). Retrieved November 6, 2014, from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A3DEC93F-E43A-48DA-B589-DD1922501ABE}

CASE 13-E-0140, Order Approving the Scorecard for Use by the Commission as a Guidance Document to Assess Electric Utility Response to Significant Outages. (2013, December 23). Retrieved November 6, 2014, from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9FFD6E37-BF89-4124-94E0-EC23BE43E71B}

CASE 90-E-1119, Order Adopting Standards on Reliability and Quality of Electric Service. (1991, July 2). Retrieved November 6, 2014, from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9A07ED41-CBB2-43B7-A8A4-D071FB0B4892}

CASE 13-E-0030, Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal. (n.d.). Retrieved February 21, 2014, from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1714A09D-088F-4343-BF91-8DEA3685A614}

OLR Research Report, Decoupling Utility Sales and Earnings. (2005, October3). Retrieved November 6, 2014, from http://www.cga.ct.gov/2005/rpt/2005-R-0702.htm

Report of the New York State Assembly Queens Power Outage Task Force. (2007, January 30). Retrieved November 6, 2014, from http://www.dps.ny.gov/06E0894/06E0894_TaskForceReport.pdf

Utility Workers Union of America,The Impact of Hurricane Sandy on Consolidated Edison of New York: Assessment of Restoration Efforts and Recommendations for the Future. (2013, February). Retrieved November 6, 2014 from https://www.google.ca/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0CB8QFjAA&url=http%3A%2F%2Fwww.rebuildbydesign.org%2Fresearch%2Fresources%2F39-community-

social%2Fdownload%2F86_93db85ed909c13838ff95ccfa94cebd9&ei=2kZqVNIi0f7JBIvOgdgK&usg=AFQjCNE1oRh6Q4Kkony2lkI12J1345RnVg&bvm=bv.79142246,d.aWw

Synapse Energy Economics, Performance-Based Regulation in a Restructured Electric Industry. (1997, November 8). Retrieved November 6, 2014 from http://www.synapse-energy.com/sites/default/files/SynapseReport.1997-11.NARUC_.PBR-in-a-Restructured-Electricity-Industry..97-U02.pdf

CASE 03-S-0640, Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation. (2004, July 9). Retrieved November 6 from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BBA525241-36BF-46E0-924F-6D8ACF19BBC3%7D

Order Requiring Proposals for Revenue Decoupling Mechanisms. (2007, April 20). Retrieved November 6, 2014 from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BC466483E-E5BA-441F-9CB8-9D722AD9350F%7D

Order Establishing Three-Year Electric rate Plan. (2010, March 26). Retrieved November 6, 2014 from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BB983F13C-AC32-40DA-A4BD-064B1EB5B6E6%7D

Electric Utility Restructuring in New York: A Status Report. Retrieved November 6, 2014 from http://www2.nycbar.org/Publications/reports/show_html_new.php?rid=15

Security and Exchange Commission, Form 10-Q. Retrieved November 6, 2014 from http://www.sec.gov/Archives/edgar/data/23632/0000023632-94-000015.txt

Consolidated Edison, Inc. Annual Report 1997. Retrieved November 6, 2014 from http://pbadupws.nrc.gov/docs/ML0936/ML093640833.pdf

Con Edison Annual Report 1991. Retrieved November 6, 2014 from http://pbadupws.nrc.gov/docs/ML1003/ML100320944.pdf

PSC Case No. 96-E-0897, Agreement and Settlement. (1991, July 2). Retrieved November 6, 2014, from http://www.dps.ny.gov/ConEd_Settlement_A_file.pdf

Re: PSC Case 09-E-0428 – Con Edison Electric Rates Con Edison's Customer Service Performance Mechanism Performance for Rate Year Ended March 31, 2013. (May 7, 2013). Retrieved November 6, 2014, from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B5031F4A2-59DB-471F-B899-A4439BA93FD0%7D

Appendix 7: United Kingdom (OFGEM)

This Appendix contains additional information related to UK jurisdiction.

Table 9: UK – Transmission Price Control Review (TPCR)

	TPCR 1	TPCR 2	TPCR 3	TPCR 4	RIIO
Form	(RPI-X) Comprehensive Building Block	(RPI-X) Comprehensive Building Block	(RPI-X) Comprehensive Building Block	(RPI+X) Comprehensive Building Block	Rev = Incentives + Innovation + Outputs Comprehensive(“Outputs”) Building Block
Term	5 years	5 years	5 years	5 years	8 years
Inflation Factor					
X factor	based on comparisons to other utilities and a total factor productivity index	based on comparisons to other utilities and a total factor productivity index	based on comparisons to other utilities and a total factor productivity index	based on comparisons to other utilities and a total factor productivity index	
Other Adjustment Factors					
Sharing Benefits					
Service Performance				Yes	Yes
Other Features			Revenue driver for additional capex Reopener	Logging up uncertain costs RPI-X to RPI+X Pensions allowance Sustainability package	Outputs focused Innovation stimulus package Increased customer engagement Low carbon longer term context

The UK was one of the first jurisdictions to implement incentive regulation using a price cap formula (RPI-X) adjustment mechanism. The section "PBR in UK" provides an overview of the PBR evolution from (RPI-X) to RIIO. In this appendix, the following are covered to have a better understanding on how RIIO model is being executed:

- Changes in UK Energy sector and networks
- RIIO Components (Revenues = Incentives + Innovation + Outputs)
- Evolution and Price Control under (RPI-X)
- Elements of the RIIO Model
- Framework for setting Outputs
- Overview of RIIO process timelines
- National Grid's perspective on RIIO

CHANGES IN THE UK ENERGY SECTOR AND NETWORKS

The energy sector is going through a tremendous change in UK and this was essentially driven by objectives to have a low carbon economy. The goal is to achieve an 80 percent reduction in greenhouse gas emissions by 2050 and decarbonised electricity generation by 2030 while maintaining security of supply.[111] To meet the 2020 EU targets, the UK would need to have 30% electricity generated from renewable resources. According to OFGEM, the challenges faced by the energy sector from low carbon targets, ageing infrastructure, security of supply and affordability[112].

The above challenges of the energy sector, in-turn created challenges for energy network services as they are the critical link for energy delivery. Decarbonisation, because of the significant targets, cannot be accomplished only by replacing electricity generation with low-carbon substitute. High- carbon applications like heating homes and transportation needs to be reviewed too.

It is estimated by OFGEM that UK energy networks will need approximately £32 billion by 2020[113] to deliver on low-carbon targets without compromising on security and reliability of supplies. Significant amounts of these investments are to replace aging

---

111 RIIO: A new way to regulate energy networks, Final Decision, October 2010, page 9.

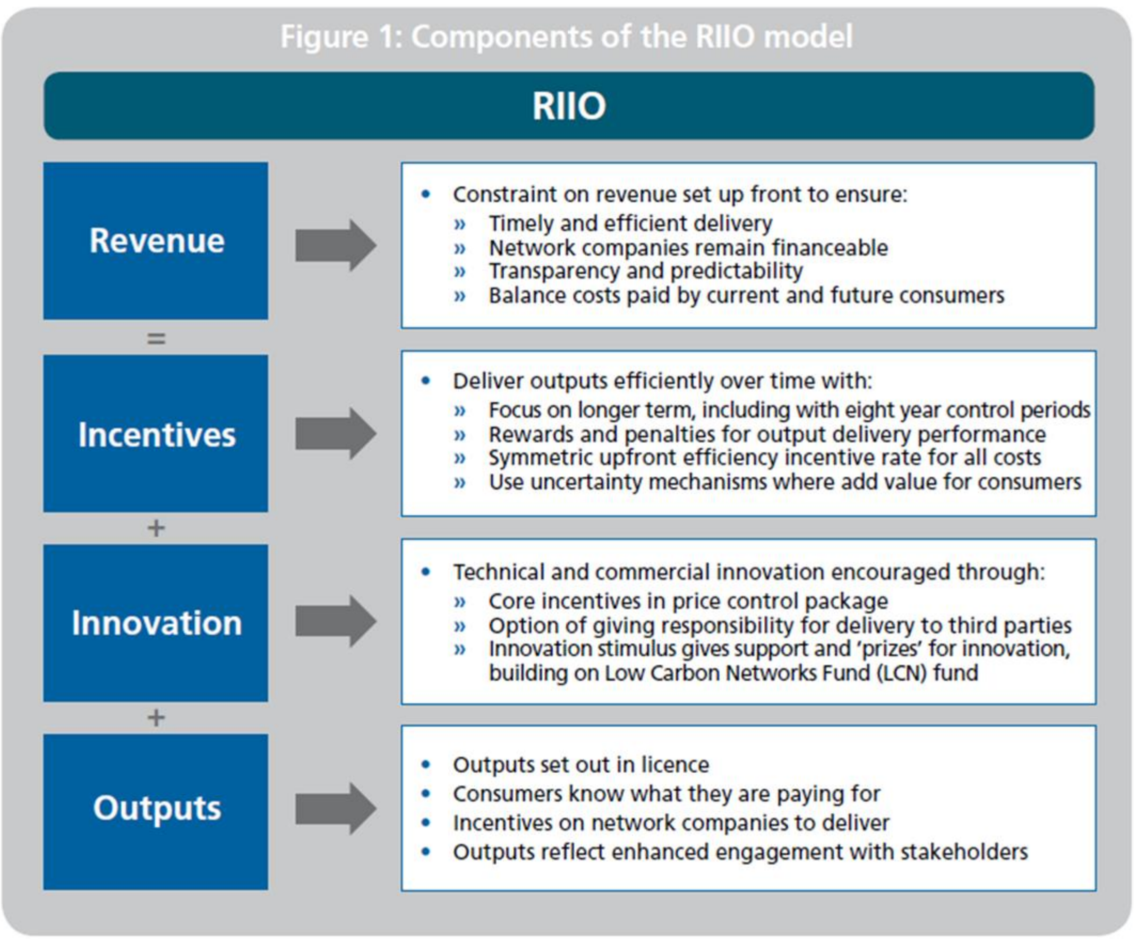
112 Ibid.

113 Ibid.

infrastructure and the rest to connect new supplies of renewable generation. The current regulatory asset value of the energy networks is approximately £43 billion. Therefore ~75% more need to be invested by 2020.

COMPONENTS OF THE RIIO MODEL

The detailed review of regulatory regime was complete in 2010 and in July 2010 OFGEM published recommendations for consultation on a new regulatory framework – Sustainable Network Regulation using the RIIO Model. The components of the RIIO model are shown below[114]:



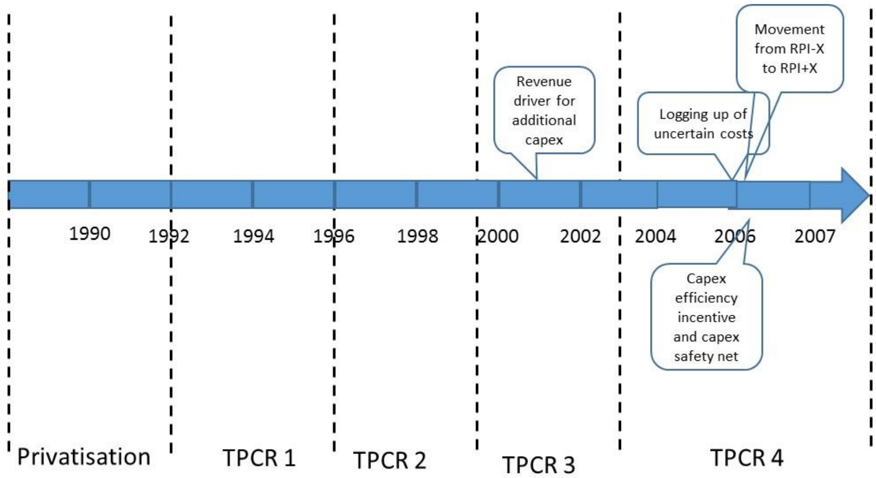
The framework aims to be transparent and proportionate, providing certainty and predictability. To encourage longer-term thinking, an eight year term was established.

---

114 RIIO: A new way to regulate energy networks, Final Decision, October 2010, page 3.

EVOLUTION AND PRICE CONTROL UNDER (RPI-X)[115]

The (RPI-X) framework was essentially focused on incentives for cost efficiencies and evolved over two decades. The following figure highlights the evolution of electricity transmission regulation over the (RPI-X) regimes.



TPCR – Transmission Price Control Review

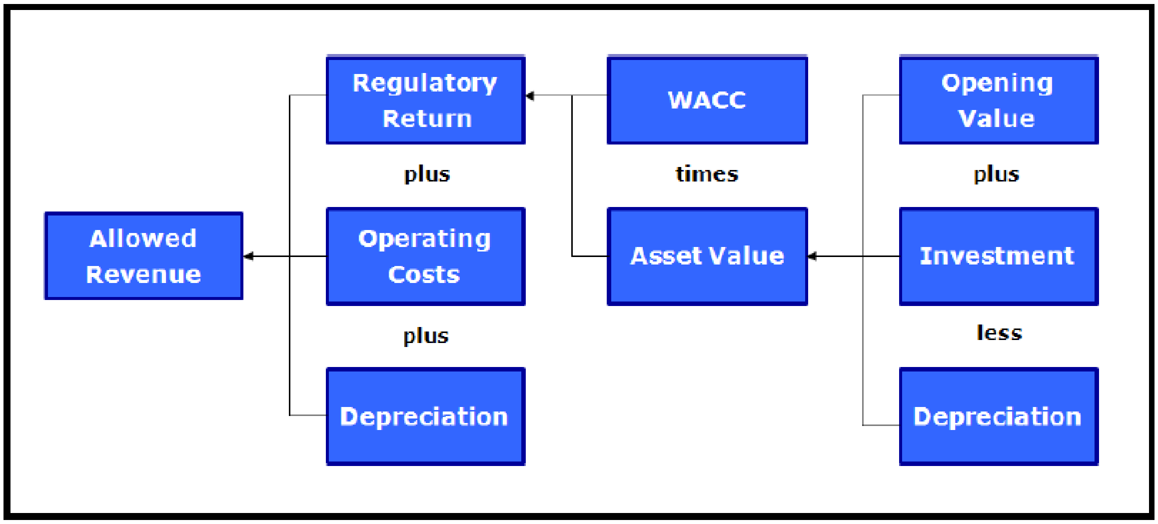
(RPI-X) is an incentive regulation framework where revenue allowances are fixed in advance for a fixed period of time with some adjustments during the term for inflation and few variables (e.g. Volume changes, customer number changes etc.). The network provider benefitted if it outperformed the assumptions. It started with cost efficiency incentives, but in later regimes, additional incentives for quality of service were introduced.

The price control revenue calculation followed is based on 'building block' [116]approach, shown below. Forecast pass-through costs are added to these estimated base costs.

---

115 History of Energy Network Regulation Ref:13b/09, 27 February 2009.

116 Ibid, page 24.



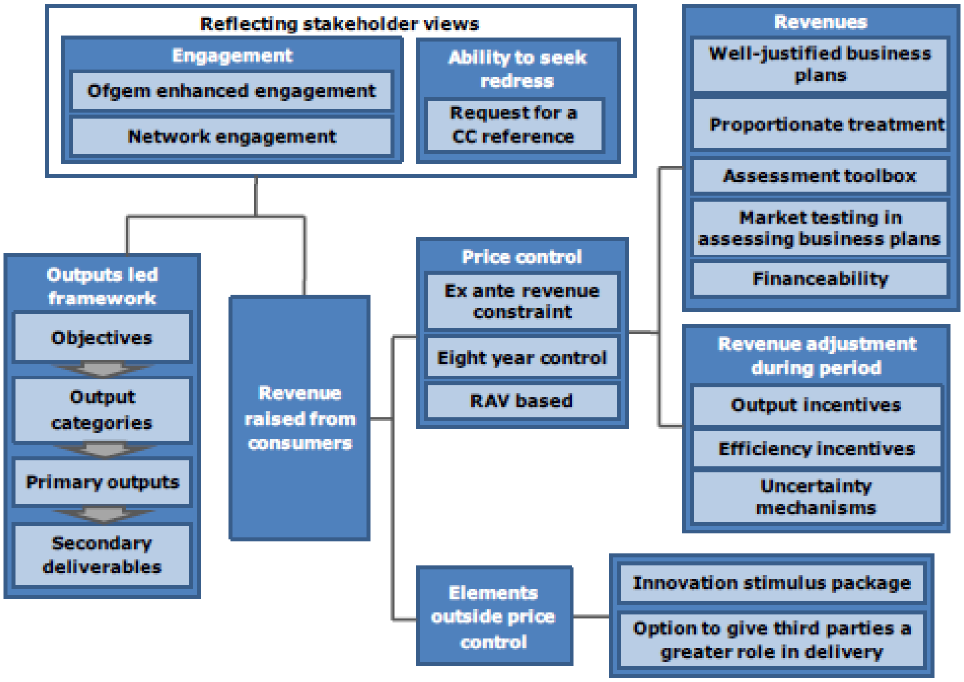
Since privatisation, each of the network providers has gone through four price control reviews. The form of price controls changed over time with external changes and new issues. The level of complexity also increased.

ELEMENTS OF RIIO MODEL[117]

The RIIO model is built on the key elements (e.g., building blocks approach) of the RPI-X framework and is augmented with new elements, like innovation, that deliver on a sustainable energy sector and provide long-term value in a low carbon future. The incentives are designed for delivery on outputs and innovation. The elements of the RIIO model are shown below. It is essentially a price-control upfront model that sets the output targets for the network companies and the revenues they are able to collect from customers to deliver on these outputs.

117 The two documents referred for this section are:
1. RIIO: A new way to regulate energy networks, Final Decision, October 2010
2.Handbook for implementing the RIIO model, October 4, 2010

Figure 1: Elements of the RIIO model



From the figure it is evident that the development involves extensive engagement reflecting stakeholder views.

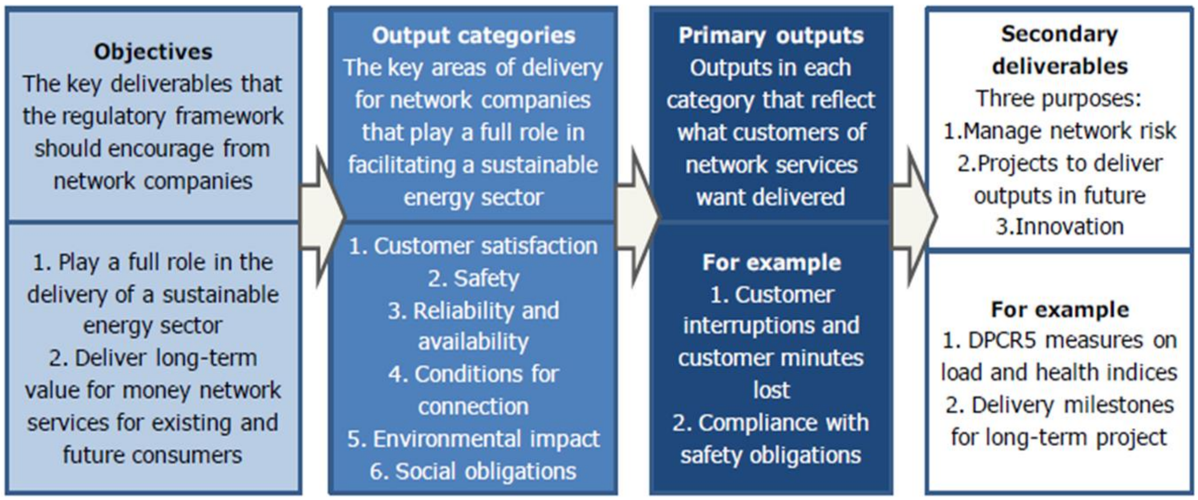
FRAMEWORK FOR SETTING OUTPUTS

The core innovation of the RIIO model is the emphasis on "Outputs". These are the outputs that networks companies need to deliver for alignment with the objectives of a sustainable energy sector.

From the high-level objectives of the RIIO model, six output categories are developed. The critical part here is the level of performance expected and determining the appropriate metrics and their respective targets. At an early stage, a baseline level of performance for each of the primary outputs will be set considering the consultation and historical performance.

To delivery on primary outputs over time, companies are expected to develop secondary deliverables. The figure below shows the connection between objectives, output categories, primary outputs and secondary deliverables.

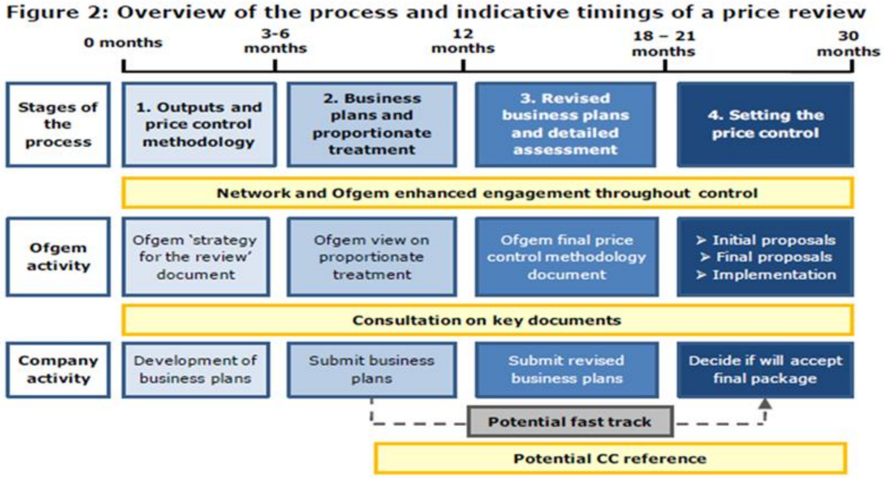
Figure 13: The framework for setting outputs



OVERVIEW OF PROCESS TIMELINES

The indicative timelines for determining the price controls are shown below:

Figure 2: Overview of the process and indicative timings of a price review



2.3. As Figure 2 illustrates, the price control process will have four main stages:

- **Stage 1** - Outputs and price control methodology;
- **Stage 2** - Business plans and proportionate treatment;
- **Stage 3** - Revised business plans and detailed assessment; and
- **Stage 4** - Setting the price control.

Some of the following process issues:

- The process of price review is 30 months. The price control term is 8 years. Therefore at the beginning on the process, the companies are expected to project costs that are ten and half years ahead.
- The starting of the baseline revenue process is “well-justified business plans”. This could be a major qualitative, data and modeling effort.
- The external environment and energy sector are continuously evolving. In this context, designing output metrics and the baseline performance could be a challenge.

NATIONAL GRID ELECTRICITY TRANSMISSION’S PERSPECTIVE ON RIIO[118]

The first price control under the RIIO model is for National Grid Electricity Transmission (RIIO-T1) and applies to the term April 1, 2013 to 31 March 2021. OFGEM released the final decision titled, “RIIO-T1: Final proposals for National Grid Electricity Transmission and National Grid Gas” on December 17, 2012.

The scope of the proposals include

- A comprehensive set of outputs and incentives to deliver them
- A package of measures to encourage innovation
- Total funding details for investment in transmission networks
- A package of mechanisms for addressing risks and uncertainty
- A financial package which provides an appropriate level of financial rewards

National Grid has accepted these proposals. It has created a website “talkingnetworksstx.com” to engage stakeholders and as a dedicated website to provide progress information on the RIIO-T1 model.

28 February 2013: Message from Steve Holliday, National Grid Chief Executive[119]

---

118 RIIO-T1: Final proposals for National Grid Electricity Transmission, Dec 17, 2012.

119 National Grid.

"I am pleased to confirm agreement of the RIIO price controls for our UK businesses. This is the culmination of a new process that started over three years ago. These arrangements give our UK businesses their longest ever period of regulatory clarity. This enables us to focus on driving efficiency across our operations while building the infrastructure that the country needs and at the same time realise the benefits of excellent performance for both customers and investors.

We are extremely grateful for the support and valuable input received from our stakeholders which has helped us shape our plans for the future. We look forward to continuing this engagement with you throughout the eight year RIIO price control period."

KEY REFERENCES

Regulating Energy Networks for the Future: RPI-X@20 History of Energy Network Regulation. (2009, 27 February). Retrieved November 6, 2014, from https://www.ofgem.gov.uk/ofgem-publications/51984/supporting-paper-history-energy-ntwork-regulation-final.pdf

Buchanan, A. (2008, March 6). Alistair Buchanan Speech, Ofgem's RPI at 20 Project. Retrieved November 6, 2014, from https://www.ofgem.gov.uk/ofgem-publications/64130/sbgi-6-march.pdf

RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas. (2012, December 12). Retrieved November 6, 2014, from https://www.ofgem.gov.uk/ofgem-publications/53599/1riiot1fpoverviewdec12.pdf

OTHER REFERENCES

Fox-Penner, P., Harris, D., & Hesmondhalgh, S. (2013, October 1). A Trip to RIIO in Your Future? Retrieved November 6, 2014, from http://www.brattle.com/system/publications/pdfs/000/004/958/original/A_Trip_to_RIIO_in_Your_Future.pdf?138670649

RIIO: A New Way to Regulate Energy Networks, Final Decision. (2010, October 1). Retrieved November 6, 2014, from https://www.ofgem.gov.uk/ofgem-publications/51870/decision-doc.pdf

RIIO-T1 Electricity Transmission Price Control – Regulatory Instructions and Guidance: Version 1.5. (n.d.). Retrieved April 16, 2014, from https://www.ofgem.gov.uk/ofgem-publications/87309/riio-t1electricitytransmissionrigsversion1.5.pdf

RIIO-T1 and GD1: Draft Regulatory Instructions and Guidance. (n.d.). Retrieved October 30, 2012, from https://www.ofgem.gov.uk/ofgem-publications/53626/riiot1andgd1draftrigs.pdf

Handbook for Implementing the RIIO Model. (n.d.). Retrieved October 4, 2010, from https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbook.pdf

Price Controls Explained. (2013, March 1). Retrieved November 6, 2014, from https://www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf

Appendix 8: Australia

This Appendix contains the additional information related to Australia jurisdiction.

Table 10: Highlights of the Evolution of the Incentive Base Regulation Regime

	1999/00-2003/2004	2004/05-2008/09	2009/2010-2013/14	2014/15-2018/19
Form	Revenue Cap with CPI-X Maximum allowed revenue based on forecasts of the cost of service over the regulatory term	Revenue Cap with CPI-X Maximum allowed revenue based on forecasts of the cost of service over the regulatory term	Revenue Cap with CPI-X Maximum allowed revenue based on forecasts of the cost of service over the regulatory term	Revenue Cap with CPI-X Maximum allowed revenue based on forecasts of the cost of service over the regulatory term
Term	5 years	5 years	5 years	5 years
Inflation Factor				
X factor				
Other Adjustment Factors				
Sharing Benefits		Forward capex allowance Carry forward mechanism for opex	Carry forward mechanism for opex with a 30/70 sharing between providers and users Carry forward mechanism for opex	Forward capex allowance with 30/70 sharing Carry forward mechanism for opex with a 30/70 sharing between providers and users
Service Performance		Service Standards Guideline Financial incentives for performance	Service Target Performance Incentive Scheme Financial incentives for performance	Service Target Performance Incentive Scheme Financial incentives for performance
Other Features		Reopening the revenue cap	Reopening of revenue determination for capital expenditure	Reopening of revenue determination for capital expenditure

GENERAL

As part of a process coordinated through the Council of Australian Governments ("COAG"), the Governments of New South Wales, Victoria, Queensland, South Australia and the Australian Capital Territory created the National Electricity Market ("NEM") in southern and eastern Australia. [120] The NEM is the wholesale electricity market for the electrically interconnected states and territories of eastern and southern Australia (i.e. Queensland, New South Wales, the Australian Capital Territory ("ACT"), Victoria, South Australia and Tasmania). West Australia and Northern Territory are not connected to the NEM.

Pursuant to the National Electricity Code ("NEC") the Australian Competition and Consumer Commission ("ACCC.") was given the initial responsibility for the regulation of distribution and transmission networks effective July 1, 1999.

The Australian Energy Market Commission ("AEMC") was established in 2005 as part of new governance arrangements to oversee the Australia's main energy markets. The AEMC was given authority to make and amend the National Electricity Rules ("NER"), the National Gas Rules and the National Energy Retail Rules which govern the NEM, elements of natural gas markets and energy retail markets.[121]

On 1 July 2005 the Australian Energy Regulator ("AER") assumed the ACCC's responsibilities for the regulation of electricity transmission revenues in the NEM. At present, the AER regulates prices that electricity networks charge to consumers in eastern and southern Australia.

Rates for electricity transmission charged by transmission service providers in Australia have been set using an incentive based regulatory regimen since 1999. The regulatory approach consists of a revenue cap with a CPI-X incentive mechanism.

The fundamental of the CPI-X revenue cap regulatory approach has not changed since incentive based regulation for transmission was introduced. However, continuous

[120] The Australian Competition and Consumer Commission. Draft Statement of Principles for the Regulation of Transmission Revenues. May 27, 1999.

[121] Australian Energy Market Commission.

development has come about by enhanced customer consultation, improved regulatory process and stronger incentives that have evolved over three regulatory terms.

On 29 November 2012, the AEMC announced changes on the electricity network regulations. The focus of the changes was to provide additional strength and flexibility to the AER. The areas impacted by new regulation were: [122]

- Rate of return determination
- Capital expenditure incentives
- Capital and operating expenditure allowances
- Regulatory determination process.

Following to the new rules announced by the AEMC, in 2013 the AER initiated the Better Regulation program to update and improve the regulatory process under the new rules, with a focus on long term interests of electricity consumers. This program was an integrated package in the way the AER approaches regulation and involved:[123]

- Extensive consultation on creating new guidelines;
- Establishing consumer reference group for guidelines development;
- Establishing ongoing Consumer challenge panel;
- Improving internal expertise and systems and communication to all stakeholders.

TransGrid is one of the operators of transmission networks in Australia. Trans Grid is the owner, operator and manager of the New South Wales's ("NSW") high voltage network connecting generators, distributors and major end users in NSW and the ACT. TransGrid is in the fourth term of the review of its transmission revenue. In May 2014 TransGrid filed its transmission revenue proposal for the 2014/15 - 2018/19 regulatory term.

---

[122] Australian Energy Market Commission. Rule Determination. National Electricity Amendment (Economic Regulation of Network Service Providers) and Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012. November 29, 2012.

[123] Australian Energy Regulator. Better Regulation – Integrated Package, May 2013.

The AEMC issued transitional rules to allow time for the AER to consult on the guidelines and to clarify how the new approach would apply to TransGrid. The transitional rules separate the 2014-19 regulatory term into two periods: a one year transitional regulatory period from July 1, 2014, to June 30, 2015; and a subsequent regulatory control period from July 1, 2015, to June, 30. 2015.[124]

The next section will provide a description of the Australia's incentive based regulation approach for electricity transmission and an overview of the major changes experienced since the implementation of incentive regulation for electricity transmission in 1999.

EVOLUTION OF REGULATION

The Initial Incentive Based Regulation Model

Prior to 1999, transmission rates were set by electricity transmission service providers using traditional rate-of-return regulation.

The passage from traditional rate-of-return regulation to an incentive based approach placed the focus on incentive. At the time of implementing incentive based regulation for electricity transmission, the ACCC observed that under traditional rate-of-return regulation any profits in excess of the regulated return was required to pass onto consumers in the form of lower tariffs and while, on the other hand, any increases in unit costs could be passed through to consumers through higher tariffs. In the ACCC's view such a regime did little to encourage efficiency improvements and indeed encouraged inefficiencies in the form of 'gold-plating' of assets and reduction in the incentive to grow the business. [125]

124 Australian Energy Regulator. Framework and Approach Paper- TransGrid, January 2014.

125 Australian Competition and Consumer Commission. Final Decision. Access Arrangement by Transmission Pipelines, Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System; Access Arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System; Access Arrangement by Victorian Energy Networks Corporation for the Principal Transmission System. October 6, 1998.

In 1999 the ACCC issued a Draft Statement of Principles for the Regulation of Transmission Revenues which set out the following objectives and principles of the transmission revenue regulatory regime: [126]

1. *the transmission pricing regulatory regime must achieve outcomes which:*
    a. *are efficient and cost effective;*
    b. *are incentive based, including the sharing of efficiency gains between network users and owners as well as the provision of a reasonable rate of return (without monopoly rents) to network owners;*
    c. *foster efficient investment, operation, maintenance and use of network assets;*
    d. *recognise pre-existing government policies on asset values, revenue paths and prices;*
    e. *promote competition; and*
    f. *are reasonably accountable, transparent and consistent over time;*
2. *the regulation of aggregate revenue of transmission networks must:*
    a. *be consistent with the regulatory objectives (see 1 above);*
    b. *address monopoly pricing concerns, wherever possible, through the competitive supply of network services but otherwise through a revenue cap;*
    c. *promote efficiency gains and a reasonable balance between supply and demand side options;*
    d. *promote a reasonable rate of return to network owners on an efficient asset base where:*
        i. *the value of new assets are consistent with take-or-pay contracts or NEMMCO augmentation determinations;*

126 Australian Competition and Consumer Commission. Overview Draft Statement of Principles for the Regulation of Transmission Revenues. May 27, 1999. Page 5.

ii. *the value of existing assets are determined by jurisdictional regulators and must be lower than their deprival value; and*

iii. *any asset revaluations undertaken by the Commission are consistent with COAG decisions;*

3. *the form of the economic regulation shall:*

   a. *be a revenue cap with a CPI-X incentive mechanism, or some other incentive based variant, for each network owner;*

   b. *have a regulatory control period of at least five years;*

   c. *take into account expected demand growth, service standards, weighted average cost of capital, potential efficiency gains, a fair and reasonable risk adjusted return on efficient investment and ongoing commercial viability of the transmission industry; and*

   d. *only apply to those assets the Commission does not expect to be offered on a contestable basis;*

4. *the TNSPs must provide the Commission with annual financial statements, and other information as required, so the Commission can monitor compliance with the revenue cap and assess cost allocation.*

The transmission regulatory regime is an accrual building block approach based on forecasts of the cost of service over a regulatory term. The building block approach calculates the maximum allowed revenue (MAR) that a transmission service provider can earn over the regulatory term as the sum of the return on capital, the return of capital (i.e. depreciation), and operating and maintenance expenditures (including administrative costs). [127]

MAR = return on capital + return of capital (i.e. Depreciation) + O&M

This regulatory framework is intended to provide assurance that transmission providers will have the opportunity to earn a reasonable (risk adjusted) return on their investment

[127] Australian Competition and Consumer Commission. Overview Draft Statement of Principles for the Regulation of Transmission Revenues. May 27, 1999. Page 4.

capital, as well as the return of capital provided the market continues to value the services produced with that capital.

The regulatory framework also recognizes that the valuation of fixed assets is central for calculating 'return on' and 'return of' capital. The ACCC adopted the depreciated optimized replacement cost ("DORC") method for the initial valuation of fixed assets. DORC is the sum of the depreciated cost of assets that would be used if the system were notionally reconfigured so as to minimize the forward looking costs of service delivery.[128]

The ACCC adopted a nominal post-tax weighted average cost of capital ("WACC") approach for determining the fair return on the asset base. For return of capital the ACCC used a competitive depreciation profile.

Consistent with the approach of other Australian regulators and in accordance with the NEC, the initial incentive based regulation model included a CPI-X adjustment mechanism. In the ACCC's view, by using this mechanism transmission providers are able to retain cost reductions and hence have a strong incentive to be more efficient. Under this arrangement, the revenue cap set for each regulated transmission operator increases each year in line with general price increases (i.e. as measured by CPI) but decreases each year by the X factor.

The initial regulatory model also included a glide path for one term beyond the regulatory term in which the efficiency gains accrued. This glide path allowed for a gradual sharing of the benefit gains between transmission providers and the users of the transmission network in the form of lower prices. Under the initial regulatory model, the gradual sharing of the benefit gains only applied to operation and maintenance expenditures. For the remaining components of the building block (i.e. rate of return and capital expenditures) no additional benefit was considered and the corresponding costs were fully readjusted from the first year of the upcoming regulatory term. At that time, the ACCC made a determination not to glide path capital expenditures. The ACCC

128 Australian Competition and Consumer Commission. Overview Draft Statement of Principles for the Regulation of Transmission Revenues. May 27, 1999. Page 5.

observed that doing so created a perverse incentive to transmission providers to over-forecast capital expenditures.

Service standards are a key component of the incentive based regulation approach for transmission in Australia. The ACCC stated that incentive based regulation requires an explicit level of service for which the regulator needs sufficient revenues to maintain the necessary assets in delivering that level of service. From the outset, the regulator has required that transmission providers file, as part of their transmission revenue cap proposal, a set of service standards and the corresponding proposed benchmarks for each standard. At the time when the ACCC issued its decision for the first transmission revenue application, the service standards were still being developed.

Based on the Initial Incentive Based Regulation Model, transmission network providers filed their transmission revenue cap applications for the 1999/00-2003/04 term.

2004/05- 2008/ 09Transmission Revenue Cap

Following to a consultation process, in 2004 the ACCC released the Statement of Principles for the Regulation of Electricity Transmission Revenues*.* Through this statement the ACCC introduced a number of changes to the initial incentive based regulation model. The ACCC's key objectives in making the changes to the initial model were: [129]

- To promote certainty;
- To improve efficiency incentives.

PROMOTING CERTAINTY

The ACCC sought to promote certainty by:

- Changing the way sunk assets were valued: with this revision sunk assets were no longer required periodic revaluation. Rather, transmission providers were required to roll forward the value of sunk assets at their depreciated historic cost, taking account of inflation.

---

129 Australian Competition and Consumer Commission. Statement of principles for the regulation of electricity transmission revenues – background paper. December 8, 2004

- Incorporating ex ante capital expenditure (capex) incentive: The ACCC moved to a regulatory incentive for capital expenditures based on the determination of investment targets, before expenditures are incurred.
- Consistency in WACC calculations: the ACCC continued to establish the WACC on the basis of benchmark parameters such as the market risk premium, the equity beta and the risk free rate.

ENERGY EFFICIENCY IMPROVEMENTS

The ACCC sought to improve efficiency incentives by:

- Moving to an ex ante investment regulatory incentive: the ACCC adopted an ex ante incentive mechanism which was intended to ensure that a transmission provider selects efficient capital projects at the lowest sustainable cost for a given level and quality of service. This ex ante incentive was specified as a capital expenditure target for each year of the regulatory term and was established at the start of each regulatory term. The mechanism allowed transmission providers to retain the depreciation and return on the difference between the actual and allowed expenditure for the regulatory term and was intended to create an efficiency incentive for a transmission provider as it will be able to achieve a higher return on its assets during the regulatory term if it spends below the expected level, while still delivering the same outputs.
- Implementing an efficiency carry forward mechanism for operating and maintenance expenditure (opex): through this mechanism a transmission provider is able to retain the benefit/loss of incremental efficiency changes for five years after the year in which that incremental change is made. The efficiency carry forward mechanism was intended to strengthen the efficiency incentive for operating and maintenance expenditures in the later years of the regulatory term and hence produce a nearly constant incentive to achieve efficiency gains over the course of the regulatory term.
- Allowing the revenue cap to be re-opened if unexpected events have a material impact on the transmission provider’s costs.

- Improving transparency of the transmission provider's cost and service performance: the ACCC sought to publish various measures of transmission performance including a quantitative valuation of the impact of transmission constraints on market outcomes.

In 2003, the ACCC released its Service Standards Guidelines which set out the framework for setting performance incentives as part of the transmission revenue cap proceeding. The Service Standards Guidelines outlined the ACCC's information requirements to implement the service standards performance incentive scheme. The guidelines set the requirement to be complied by transmission providers for annual reporting on service standard performance. This allowed incorporating any reward/penalty into the transmission providers' charges for the subsequent year. [130]

Based on the Statement of Principles for the Regulation of Electricity Transmission Revenues, transmission providers filed their transmission revenue cap application for the 2004/05- 2008/09 term.

2009/10 - 2103/14 Transmission Revenue Cap

Transmission revenue cap applications for the 2009/10-2013/14 term incorporated the Efficiency Benefit Sharing Scheme (EBSS) and the Service Target Performance Incentive Scheme (STPIS).

THE EFFICIENCY BENEFIT SHARING SCHEME

In 2007 the regulator, at that time the AER, implemented the EBSS which took the form of the existing efficiency carry forward mechanism. The AER sought that the EBSS mechanism provided for a fair sharing of efficiency gains and determined that efficiency savings or losses were shared approximately 30:70 between the transmission service provider and users of the transmission network. In fact, the AER established a notional five-year period for the carryover and an effective 30:70 sharing ratio. The AER determined that in absence of evidence that a transmission provider is approaching the efficiency frontier, the five-year carry over period should be maintained. The EBSS is

130 Australian Competition and Consumer Commission. Final Decision. NSW and ACT Transmission Network Revenue CapTransGrid 2004–05 to 2008–09. April 27, 2005.

currently in place and the AER is allowed to reconsider the appropriateness of the carry over period and the sharing ratio if the transmission provider presents evidence that it is approaching the efficiency frontier. [131]

The Service Target Performance Incentive Scheme

In August 2007 the AER issued a final decision which set out the service target performance incentive scheme ("STPIS"). The STPIS outlined the approach that the AER used to set the STPIS within the transmission determination framework. The key objectives of the STPIS were: [132]

- To contribute to the NEM objective;
- To provide consistency with the principles set out in NER;
- To promote transparency in the information provided by a transmission service provider and AER decisions;
- To assist in setting efficient capital and operating expenditure allowances in transmission determinations by balancing the incentive to reduce actual expenditure with the need to maintain and improve reliability for customers.

The STPIS provided financial rewards for improvements in performance standards and penalties when performance standards decline against a performance target.

The Better Regulation Program

As part of the Better Regulation program, in 2013 the AER initiated a process to enhance the approach to be used in regulating electricity networks. Underpinning principles guiding the AER's role in regulating electricity networks were as follows:

- Where possible economic regulation should be incentive-based;
- Necessary and efficient investment should be encouraged;
- There should be strong consumer engagement framework.

---

[131] Australian Energy Regulator. Electricity transmission network service providers, efficiency benefit sharing scheme. September 2007.

[132] Australian Energy Regulator. Final decision, Electricity transmission network service providers service target performance incentive scheme. August 2007.

The Better Regulation program brought together a number of reforms to enhance the AER's regulatory model, including new annual reporting on efficiencies, new tools to assess business expenditure forecasts, stronger incentives, better way to determine the return on investment and a better consumer engagement framework. The AER's approach was set out through a series of guidelines. The workstream and purpose of the Better Regulation program were as follows: [133]

Table 11: Better regulation – Workstream and Purpose

Workstream	Purpose
Expenditure forecast assessment guideline	Assessing expenditure proposals from businesses.
Rate of return guidelines	Determining the allowed rate of return businesses earn on their investments.
Expenditure incentives guideline	Creating the right incentives to encourage efficient spending by businesses.
Consumer engagement guideline for network service providers	Implementing consumer engagement strategies that are effective for all stakeholders.
Rate of return guidelines	Determining the allowed rate of return businesses earn on their investments.
Expenditure incentives guideline	Creating the right incentives to encourage efficient spending by businesses.
Consumer engagement guideline for network service providers	Implementing consumer engagement strategies that are effective for all stakeholders.
Rate of return guidelines	Determining the allowed rate of return businesses earn on their investments.
Expenditure incentives guideline	Creating the right incentives to encourage efficient spending by businesses.

The AER has made available on its website the guideline documents, explanatory statements and factsheets for all the workstream.[134]

The Better Regulation program provided opportunities for consumer involvement. The AER expects that the new regulatory framework provides opportunities to consumers to express their views and preferences. The AER also expects that consumers' views and preferences be heard and influence transmission providers' decisions. The AER has

133 Australian Energy Regulator. Overview of the Better Regulation reform package, April 2014.

134 They are available on the AER's Better Regulation web page

developed a guideline which provides a high level framework to integrate consumer engagement into network service providers' business-as-usual operations. The AER expects that all network providers use the consumer engagement guideline to enhance their ongoing consumer engagement activities. The AER set forth that when assessing proposed expenditure proposals it will consider how a business has engaged with its consumers and accounted for the long term interests of the consumers. Network providers must describe in their proposals how they have engaged with consumers, and how they addressed any relevant concerns identified as a result of that engagement. Network providers are required to demonstrate a commitment to provide services that better align with consumers' long term interests.[135]

This appendix discusses below the changes made by the AER, as part of the Better Regulation program, on expenditure incentives, the assessment of expenditures forecasts and consumer engagement. Although the Better Regulation reform did not make changes to the STPIS, an overview is also provided on the revisions made by the AER to this scheme in 2012.

EXPENDITURE INCENTIVES

The AER notes that the expenditure incentive schemes are designed in a manner that network providers are encouraged to make efficient decisions when choosing whether to incur opex or capital spending. As such:

> *Our expenditure incentive schemes provide balanced and constant incentives so a business can make efficient decisions when choosing whether to incur opex or capex. In this way, trade-offs between capex and opex are incentive neutral. For example, suppose a business decides to spend money on opex which it would otherwise have spent on capex. Under our expenditure incentive schemes the business incurs a 30 per cent penalty for becoming less efficient with opex, but this is offset by a 30 per cent reward for becoming more efficient with capex.*[136]

[135] Australian Energy Regulator. Better Regulation Reform package update. August 2013. Page 5.

[136] Australian Energy Regulator. Overview of the Better Regulation Reform Package. April 2014. Pages 7- 8.

With respect to depreciation changes, the AER aimed at providing stronger incentives for efficient capital expenditures by using actual depreciation rather than forecast depreciation to roll forward into the regulatory asset base. Under the current regulatory approach, depreciation approach is one part of the overall capital expenditure incentive framework and supplements the incentive provided by the CESS mechanism. If there is a capex underspend, actual depreciation will be lower than forecast depreciation. As a result, the regulatory asset base will increase more at the next regulatory term than what it would be if forecast depreciation were used. That means that the transmission provider will be able to earn more in the future than if forecast depreciation is used to roll forward into the regulatory asset base.

The AER also developed an approach for ex post measures to incent efficient and prudent capital expenditures over the regulatory term. Specifically, the AER developed a process to support any decision pertaining to the efficiency and prudency of all capital expenditures to be rolled into the regulatory asset base. This process consists of two phases. In the first stage the AER assesses the transmission provider's actual capital expenditure performance. As part of the second stage, the AER performs a detailed assessment of the drivers of the transmission provider's capital expenditures and the provider's management planning tools and practices. This undertaking requires the support of engineering experts and other external consultants.

THE ASSESSMENT OF EXPENDITURE FORECASTS

The AER notes that its assessment tools and techniques are underpinned by a nationally consistent framework.

For the purpose of a determination or a decision with respect to a capital expenditure proposal, the AER reviews past capital spending and future capital needs. Specifically, the AER performs the following tasks:[137]

- It assesses capex forecast for the test period.

[137] Australian Energy Regulator. Overview of the Better Regulation Reform Package. April 2014. Page 11.

- It updates the network service provider’s regulatory asset base (RAB) by including the capex spent in the past during the period. In the future, any inefficient capital overspending will be excluded.
- It calculates the rewards and penalties the network provider is projected to receive under the CESS for capital underspending or overspending incurred during the term.

The AER also reviews past and total opex. Specifically:

- It assesses the proposed opex projected for the next term;
- It calculates the rewards and penalties (carryover amounts) the network provider will receive under the EBSS for operation performance during the term.

CONSUMER ENGAGEMENT

The AER issued a consumer engagement guideline which sets out how network providers will engage with their consumers. Network providers are required to demonstrate a commitment to provide services that better align with consumers' long term interests. The network service providers must develop and implement consumer engagement strategies. Under this approach, network providers are required to comply with the best practice principles that underpin the consumer engagement guideline. As can be seen in Figure 2 on the next page, the guideline includes four components that set out a process for network providers to develop and implement new or improved consumer engagement activities consistent with best practice principles.

As part of the Better Regulation program, the AER established a Consumer Challenge Panel comprising of thirteen members. The Panel expects to provide input on consumer perspectives to better balance the range of views considered as part of AER’s determinations.

Figure 2 Better Regulation consumer engagement guideline

CONSUMER ENGAGEMENT GUIDELINE OBJECTIVE
Aligning network services with the long term interests of consumers

BEST PRACTICE PRINCIPLES

Clear, accurate and timely communication	Accessible and inclusive	Transparent	Measurable
Business should provide information to consumers that is clear, accurate, relevant and timely, recognising the different communication needs and wants of consumers.	Businesses should recognise, understand and involve consumers early and throughout the business activity or expenditure process.	Businesses should clearly identify and explain the role of consumers in the engagement process, and to consult with consumers on information and feedback processes.	Businesses should measure the success, or otherwise, of their engagement activities.

COMPONENTS

Priorities	Delivery	Results	Evaluation and review
Identify consumer cohorts, and the current views of those cohorts and their service provider; outline their engagement objectives; and discuss the processes to best achieve those objectives.	Address the identified priorities via robust and thorough consumer engagement.	Articulate the outcomes of their consumer engagement processes and how they measure the success of those processes reporting back to us, their business and consumers	Periodically evaluate and review the effectiveness of their consumer engagement processes.

Sources: Australian Energy Regulator. Overview of the Better Regulation Reform Package. April 2014. Page 18.

Network providers are required to describe in their revenue proposals how they have engaged with consumers and how they have addressed any relevant concerns identified as a result of that engagement. When assessing expenditure proposals the AER will consider how a business engaged with its consumers and accounted for the long term interests of the consumers.

STPIS REVISIONS

As earlier indicated, the AER did not review the STPIS scheme as part of the Better Regulation program. However, the AER has made various revisions to this scheme since its implementation in 2007.

KEY REFERENCES

The Australian Competition and Consumer Commission. Draft Statement of Principles for the Regulation of Transmission Revenues. May 27, 1999.
http://www.aer.gov.au/sites/default/files/Draft%20statement%20of%20regulatory%20%20principles%20overview%20%2827%20May%201999%29.pdf

National Electricity Rules Version 66, as of December 1, 2014
http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Current-Rules

Australian Energy Regulator. Overview of the Better Regulation Reform Package. April 2014.
http://www.aer.gov.au/sites/default/files/AER%20Overview%20of%20the%20Better%20Regulation%20reform%20package.pdf

OTHER REFERENCES

Australian Competition and Consumer Commission. Statement of principles for the regulation of electricity transmission revenues – background paper. December 8, 2004
http://www.aer.gov.au/sites/default/files/Statement%20of%20regulatory%20principles%20-%20background%20paper%20-%208%20December%202004_1.pdf

The Better Regulation Program

Australian Energy Market Commission. Rule Determination. National Electricity Amendment (Economic Regulation of Network Service Providers) and Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012. November 29, 2012.
http://www.aemc.gov.au/Media/docs/Final-Rule-Determination-4c10cf40-03a0-4359-8fe9-3e95a446579d-0.pdf

Better Regulation reform program
http://www.aer.gov.au/Better-regulation-reform-program

Australian Energy Regulator. Explanatory Statement Expenditure Forecast Assessment Guideline. November 2013, 2013. http://www.aer.gov.au/sites/default/files/Expenditure%20Forecast%20Assessment%20Guideline%20-%20Explanatory%20Statement%20-%20FINAL.pdf

Australian Energy Regulator. Expenditure incentives guideline http://www.aer.gov.au/node/18869

Service target performance incentive scheme

Australian Energy Regulator. Service target performance incentive scheme version 4.1 - September 2014 amendment. Final Decision. Electricity transmission network service providers, service target performance incentive Scheme. September 2014.

https://www.aer.gov.au/sites/default/files/Final%20Decision%20-%20%20service%20target%20performance%20incentive%20scheme%20version%204.1%20-%20explanatory%20statement_0.pdf

Australian Energy Regulator. Service target performance incentive scheme version 4 - December 2012 amendment. Final. Electricity transmission network service providers, service target performance Incentive scheme. December 2012

https://www.aer.gov.au/sites/default/files/AER%20Final%20decision%20-%20Electricity%20TNSP%20Service%20target%20performance%20incentice%20scheme%20-%20December%202012.pdf

Service target performance incentive scheme version 1 - August 2007 amendment. Final decision. Electricity transmission network service providers, service target performance incentive scheme. August 2007. https://www.aer.gov.au/sites/default/files/Final%20decision%20service%20target%20performance%20incentive%20scheme%20-%201%20August%202007.pdf

Australian Competition and Consumer Commission. Decision. Statement of principles for the regulation of transmission revenues, service standards guidelines. November 12, 2003.
https://www.aer.gov.au/sites/default/files/Service%20standard%20guidelines%20-%2012%20November%202003.pdf

TransGrid's Transmission Revenue Cap Decisions

Australian Energy Regulator. TransGrid - Determination 2014-2019
https://www.aer.gov.au/node/23137

Australian Energy Regulator. Framework and Approach Paper- TransGrid, January 2014.
http://www.aer.gov.au/sites/default/files/AER%20Framework%20and%20approach%20-%20TransGrid%20-%20January%202014.pdf

Australian Energy Regulator. TransGrid transmission determination 2009–10 to 2013–14. April 28, 2009.
https://www.aer.gov.au/sites/default/files/TransGrid%20final%20decision.pdf

Australian Competition and Consumer Commission. Final Decision. NSW and ACT Transmission Network Revenue Cap. TransGrid 2004–05 to 2008–09. April 27, 2005.
http://www.aer.gov.au/sites/default/files/Decision%20-%20TransGrid%20(27%20April%202005)%20.pdf

Australian Competition and Consumer Commission. Decision. NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04. January 25, 2000.
http://www.aer.gov.au/sites/default/files/NSW%20and%20ACT%20revenue%20cap%20decision%20(25%20January%202000).pdf

Appendix 9: Norway

This Appendix contains additional information related to Norway jurisdiction.

Table 12: Overview of Norway Regimes

	1997-2001	2002-2006	2007-2012	2013-2018
Form	Revenue cap (CPI-X)	Revenue cap (CPI-X)	Revenue cap (yardstick)	Revenue cap (yardstick)
Term	5 years	5 years	5 years	5 years
Inflation Factor				
X factor	X factor evaluation by DEA	X factor evaluation by DEA		
Other Adjustment Factors				
Sharing Benefits				
Service Performance	CENS (from 2001)	CENS	CENS	CENS
Other Features				

Cost of Energy Not Supplied (CENS)

CENS, which is integrated into the revenue cap formula, is the base of the quality regulation in Norway. The purpose of this arrangement is to motivate companies to operate and maintain their network in a way that is optimal for society and that offers a satisfactory level of continuity of supply. The cost of energy not supplied affects cost norm and revenue cap, because it is included in the cost base, and network companies do not have motivation to reduce costs at the expense of quality. The interruption cost is computed for all end-users for every interruption, and the total annual cost of interruption is incorporated in the revenue cap formula.

CENS includes both planned and unplanned interruptions. The interruption is considered planned or notified if the information about interruption is provided in an appropriate manner and if the interruption is announced a reasonable amount of time prior to its occurrence. The interruption that is not appropriately notified is considered an unplanned or non-notified interruption.

Until 2009, CENS considered only interruptions longer than three minutes in networks over 1kV. From 2009, interruptions with duration less than 3 minutes have also been included in CENS. To include interruptions with duration less than 3 minutes, the cost rates were determined as a function of the outage duration.

The costs that customers incur due to interruptions are identified through national surveys. The information is collected for all types of customers which are divided into six groups; agriculture, residential, industry, commercial, public and large industry.

The survey also provides information about difference in interruption costs by season, weekdays and time of the day. Time dependency in the interruption cost is used to determine correction factors. The correction factor for day event is assigned for six periods of the day; 0h-6h: 06h-08h, 8h-12h, 12h-16h, 16h-20h, 20h-24h. The correction factor for weekday event, is allocated for Mondays through Fridays, Saturdays and Sundays/holidays, while the monthly variation is given by a factor per month. If the duration of one interruption includes several periods, a weighted average of the correction factors should apply. The correction factors are also used to adjust interruption costs of notified interruption. The interruption costs for both, planned and unplanned interruption are calculated as a non-notified interruption, but the interruption costs of notified interruption are multiplied with the correction factors.

In Norway, the reporting of the long interruption data (>3 minutes) became mandatory in 1995, and grid companies have been required to report short interruption data (<=3 minutes) since 2006. The common continuity indicators include SAIFI[138], CAIFI[139],

[138] SAIFI -System average interruption frequency index.

[139] CAIFI-Customer average interruption frequency index.

SAIDI[140], CAIDI[141] and CTAIDI[142]. The collection of information, reporting and computation of indices is standardised[143].

In 2007, the NVE introduced a direct payment to customers due to very long outages (>12 hours) in order to motivate companies to repair an outage as quickly as possible. If the outage lasts for more than 12 hours, the company is obliged to directly compensate the end users that are affected by the outage. The payment schedule is as follows:

- For an interruption of 12 to 24 hours: 600 NOK
- For an interruption 24 to 48 hours: 1.400 NOK
- For an interruption 48 to72 hours: 2.700 NOK
- For an interruption that lasts for more than 72 hours: NOK 1300 for each 24-hour period (after 72 hours).

Each year, NVE publishes a statistical report on interruptions presenting information of continuity supply at country level, county level, company level and end-user level. Three incidents that resulted in high amount of energy not supplied took place in 2003, 2006, and 2011. These incidents were caused by hurricanes, leaving a large number of customers without a power supply.

DEA

The DEA model is based on relative comparison of the network companies based on input and outputs. The total cost is the input variable. The costs included in cost base are:

- operating and maintenance costs (O&M),
- cost of power losses,
- costs of energy not supplied (CENS), and
- capital costs

140 SAIDI-System average interruption duration index.

141 CAIDI-Customer average interruption duration index.

142 CTAIDI-Customer total average interruption duration index.

143 FASIT- the standardized reporting system for faults and interruptions.

Outputs are most representative cost drivers, found by comprehensive statistical testing. Costs and output related to the parts of central grid that are not owned by Statnett are included in regional grid analyses. The five output variables for regional and central grids are, as follows:

- Weighted value of overhead lines
- Weighted value of underground cables
- Weighted value of submarine cables
- Weighted value of station components (switches, transformers, compensators)
- Forest

The current DEA model for distribution grid, adopted in 2013, includes one input (total costs) and the following three outputs:

- number of customers,
- the length of the high voltage (HV) network in kilometres, and
- the number of substations

The first stage of analysis involves the calculation of DEA results. In the second stage, these DEA results are corrected through regression analysis. The results from the analysis in each model are calibrated to ensure that companies receive a reasonable rate of return on invested capital. If efficiency scores are not calibrated, most companies will not be able to cover their costs and obtain a reasonable rate of return, because very few companies will be efficient due to the model set up. Results are calibrated so that average company is 100% efficient. The company regarded as average efficient by this analysis, earns a return on capital equal to the WACC. The efficiency scores of companies that own both distribution and regional grid are merged to get an overall efficiency score. The results are weighted based on how large a share of the company's costs is caused by each grid.

Efficiency results are multiplied with the company's cost base to get the cost norm. A cost norm of inefficient companies will be below their cost norm, and they'll have an incentive to reduce costs to become more efficient. The cost norm is also calibrated to ensure that the total revenue cap for the industry is equal to the total cost base.

E3GRID STUDY

The benchmarking of Statnetts' transmission grid is based on the results of e3grid study. The DEA is used as the benchmarking method. The model has one input parameter and three output parameters. The input parameter is total expenditures (Totex), which is the sum of operating expenditures (Opex) and capital expenditures (Capex). The three output parameters are:

- Normalized grid (cost-weighted measure of the assets in use)
- Densely populated area
- Value of weighted angular towers

The cost base may be adjusted, because companies are allowed to claim any company specific cost if it is properly determined. The claims that have resulted in the adjustment, so far, were related to

- Structural claims
    - higher costs due to lines in mountainous regions;
    - higher costs due to lines in coastal areas; and
    - higher costs for cables in cable tunnels.
- Individual claims

The calculation of efficiency scores include:

- Calculation of efficiency scores for the full sample;
- Outlier analysis to detect TSOs with extreme observations;
- Removing outliers from the full sample and recalculate efficiency scores; and
- Applying Capex break methodology where appropriate

The companies that have been considered outliers receive 100% efficiency score. After obtaining efficiency scores, the sensitivity analysis for the DEA efficiency results is performed. The sensitivity analysis can be classified in three groups, as follows:

- Variations to model specification

- Variations to model data
- Second-stage analysis to check whether there is evidence some parameters may be included in the analysis.

The following tables illustrate the recent E3grid2012 base model and efficiency results:

Table 13: DEA Model Parameters

Sample	21TSOs
Input	Totex
Outputs	Normalized grid, densely populated area and value of weighted angular towers
Return to scale	Non decreasing return to scale
Weight restriction	+/-50% of the cost elasticity estimated in a regression model with the above variables
Selected Capex break	2 TSOs

Source: E3GRID2012 – European TSO Benchmarking Study

Table 14: Efficiency Results

Average Efficiency (with outliers)	86%
Min Efficiency (with outliers)	59%
Outliers	4
100% scores	8

Source: E3GRID2012 – European TSO Benchmarking Study

KEY REFERENCES

Economic Regulation of Electricity Gruds in Nordic Countries. (2011, December 1). Retrieved November 7, 2014, from http://www.nordicenergyregulators.org/wp-content/uploads/2013/02/Economic_regulation_of_electricity_grids_in_Nordic_countries.pdf

Economic Regulation of TSOs in the Nordic Countries. (2012, December 1). Retrieved November 7, 2014, from http://www.nordicenergyregulators.org/wp-content/uploads/2013/05/TSO_report1.pdf

NVE. (2013). National Report 2014. Retrieved November 17, 2014, from http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202014/NR_En/C14_NR_Norway-EN.pdf

OTHER REFERENCES

Report on Regulation and the Electricity Market. (2011, July 31). Retrieved November 7, 2014, from http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National Reporting 2011/NR_En/C11_NR_Norway-EN.pdf

Reg. No. 1557 of 30 November 2004: Regulations Relating to the Quality of Supply in the Norwegian Power System. (2004, November 30). Retrieved November 7, 2014, from http://www.regjeringen.no/Upload/OED/Vedlegg/Lover%20og%20reglement/Reg_No_1557_of_30_November_2004.pdf

Annual Report 2011, The Norwegian Energy Regulator. (2012, June 1). Retrieved November 7, 2014, from http://webby.nve.no/publikasjoner/rapport/2012/rapport2012_19.pdf

5th CEER Benchmarking Report on the Quality of Electricity Supply 2011. (2012, April 1). Retrieved November 7, 2014, from http://www.energy-community.org/pls/portal/docs/1522177.PDF

Agrell, P., & Bogetoft, P. (2012, December 20). Guidelines of Good Practice on Estimation of Costs Due to Electricity Interruptions and Voltage Disturbances -post Regulation, Preproject 2: Final Report. Retrieved November 7, 2014, from http://www.sumicsid.com/reg/papers/fp2_final.pdf

Heggset, J., Kjolle, G., & Mogstad, O. (n.d.). FASIT: The Norwegian Standard For Collection, Calculation and Reporting of Reliability Data. Retrieved November 7, 2014, from https://www.sintef.no/project/KILE/Publikasjoner/CIRED2009_0716_paper.pdf

Economic Regulation of Electricity Grids in Nordic Countries. (2011, December 1). Retrieved November 7, 2014, from http://www.nordicenergyregulators.org/wp-content/uploads/2013/02/Economic_regulation_of_electricity_grids_in_Nordic_countries.pdf

Acts Relating to the Energy and Water Resources Sector in Norway (unofficial translation). (2004, June 25). Retrieved November 7, 2014, from http://www.ub.uio.no/ujur/ulovdata/lov-19171214-017-eng.pdf

Tore Langset.,& Silje Cathrine. (2013) *A new WACC model in the regulation of the Norwegian electricity network operators*, Oslo,Norway.

Frontier Economics, Trends in electricity distribution network regulation in North West Europe. (2012, August). Retreived November 7, 2014 from http://www.nve.no/PageFiles/13979/Distribution%20network%20regulation%20in%20Norway%20-%20final%20-%20stc.pdf?epslanguage=no

Finn R. Førsund., & Sverre A.C. Kittelsen, (1995) *Productivity development of Norwegian electricity distribution utilities, Oslo, Norway.*

Agrell, P., & Bogetoft, P. (2009), March 09 International Benchmarking of Electricity Transmission System Operators, e3grid Project-Final Report. Retrieved November 17, 2014, from
https://www.acm.nl/nl/download/bijlage/?id=8813

E3GRID2012 –European TSO Benchmarking Study. (2013, July). Retrieved November 17, 2014, from
http://www.nve.no/Global/Kraftmarked/Frontier-Sumicsid-Consentec_e3grid2012-European%20TSO%20Benchmarking%20Study-%20final%20report_25%2007%202013-dynamic%20update-stc.pdf

Development of Best Practice Recommendations on Regulatory Incentives Promoting Infrastructure. (2011, November 23) Retrieved November 17, 2014, from.
http://www.energy-community.org/pls/portal/docs/2514183.PDF

NVE. (2013).Is there a need for rethinking the regulation of Statnett? Retrieved November 17, 2014, from
http://www.nve.no/Global/Seminar%20og%20foredrag/Energidagene2013/Sesjon8/Sesjon%20Statnett%20-%201%20Flataker.pdf

Brunekreeft, G. (2012, October). On the role of international benchmarking of electricity Transmission System Operators facing significant investment requirements. Retrieved November 17, 2014, from
http://www.bremer-energie-institut.de/download/bewp/bewp12.pdf

(n.d.). Retrieved November 17, 2014, from
http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202014/NR_En/C14_NR_Norway-EN.pdf

(n.d.). Retrieved November 17, 2014, from
http://www.sumicsid.se/web-files/docs/projects/SUMICSID_Report_ECOM+_2003.pdf

Climate Change Law and Regulations: Planning for a Carbon-Constrained Regulatory Environment. (n.d.). Retrieved November 17, 2014, from http://www.nera.com/publications/archive/2014/e3grid-was-machen-wir-mit-den-ergebnissen-des-effizienzbenchma.html

Appendix 10: Further Reading for Sections 2 and 3

Spurr, Henry C. (1924-25) *Guiding Principles of Public Service Regulation*, 2 volumes, Public Utilities Reports Inc., Washington D.C.

Troxel, Emery (1947) *Economics of Public Utilities*, Rinehart & Co., Inc. N.Y.

Bonbright, James C. (1961) *Principles of Public Utility Rates*, Columbia University Press, New York.

Priest, A.J.G. (1969) *Principles of Public Utility Regulation*, 2 vols., The Michie Co., Charlottesville, Va.

Kahn, Alfred E., (1970-71) *The Economics of Regulation*, Principles and Institutions, 2 vols., John Wiley & Sons, N.Y.

Bonbright, James C., Albert L. Danielson and David R. Kamerschen, (1988) *Principles of Public Utility Rates* (2nd ed.), Public Utilities Reports Inc., Washington, D.C.

Phillips, Charles F., Jr. (1993) *The Regulation of Public Utilities*, (3rd ed.) Public Utilities Reports Inc., Washington, D.C.

Crew, Michael A. edited by (1994) Incentive Regulation for Public Utilities, Kluwer Academic Publishers, Norwell, Mass.

Goodman, Leonard Saul (1998) *The Process of Ratemaking*, 2 vol., Public Utilities Reports Inc., Washington, D.C.

Lesser, Jonathan A., and Leonardo R. Giacchino (2013) *Fundamentals of Energy Regulation*, Public Utilities Reports Inc., Washington, D.C.

Baumol, William J., "Productivity Incentive Clauses and Rate Adjustment for Inflation", *Public Utilities Fortnightly*, July 22, 1982.

Joskow, Paul L., (2006) Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks, MIT. Joskow, Paul L., "Incentive Regulation for Electricity Networks," *Journal for Institutional Comparisons (CESifo DICE REPORT)*, 2006.

Kaufmann, Lawrence and Lullit Getachew, Matthew Makos, and John Rich, "System Reliability Regulation: A Jurisdictional Survey", May 2010.

Kaufmann, Lawrence and Mark N. Lowry, "Alternative Regulation for North American Electric Utilities." 2006. *The Electricity Journal* 19 (5): 15-26.

Kaufmann, Lawrence and Mark N. Lowry, "Performance-Based Regulation of U.S.

Electric Utilities: The State of the Art and Directions for Further Research". Palo Alto: Electric Power Research Institute, December 1995.

Kaufmann, Lawrence and Mark N. Lowry, "A Price Cap Designers Handbook". Washington: Edison Electric Institute, 1995.

Laffont, Jean-Jacques and Jean Tirole, "A Theory of Incentives in Procurement and Regulation", The MIT Press, 1993.

Littlechild, Stephen C., "Regulation of British Telecommunications' Profitability: Report to the Secretary of State", (London: Dept of Industry, 1983).

Lowry, Mark N. and Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," 2013. Edison Electric Institute.

Lowry, Mark N. and Lullit Getachew, "Price Control Regulation in North America: Role of Indexing and Benchmarking," 2009. *The Electricity Journal*, 22: 63-76.

Lowry, Mark N., and Lawrence Kaufmann, "Performance-Based Regulation of Utilities", *Energy Law Journal*, Volume 23, No. 2, 2002

Ofgem. "Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control," available at https://www.ofgem.gov.uk/publications-and-updates/strategy-decision-riio-ed1-overview. March 4, 2013.

Sudit, E. Fred. "Automatic Rate Adjustments Based on Total Factor Productivity Performance in Public Utility Regulation", in *Problems in Public Utility Economics and Regulation*, (Michael A. Crew ed., Lexington Books, 1979).

The Regulatory Assistance Project, "Performance-Based Regulation for Distribution Utilities", December 2

Appendix 11: Definitions and Acronyms

LIST OF DEFINITIONS

Benchmarking

A process of measuring utility's performance results by comparing it to defined standards.

Capital Expenditure Sharing Scheme

A scheme that provides financial rewards/penalties for utilities whose capex becomes more efficient /less efficient.

Capex

An amount spent to acquire or upgrade physical assets.

Capital Tracker

The method for addressing capital needs that are not funded under the I-X mechanism.

Competitive Market

A market in which no participants are large enough to have the market power to influence the price of the good or service.

Decoupling Mechanism

A mechanism eliminates the volumetric charge, often used to eliminate a utility's disincentives to promote energy efficiency without negatively affecting their revenues.

Distribution

The process of moving electricity from the transmission system to end users.

Earnings Sharing Mechanism

An adjustment mechanism based on the utility's rate of return.

Efficiency Benefit Sharing Scheme

A scheme that provides for sharing between utilities and customers of the efficiency gains and/or losses (generally variance form forecast).

Efficiency Carryover Mechanism

A mechanism that allows utilities to carry over efficiency gains from one regulatory period to another.

Electric Revenue Adjustment Mechanism

A revenue true-up mechanism that eliminates revenue impact of sales fluctuations.

External Benchmarking

A way of measuring a utility's performance against external standards.

Hybrid Mechanisms

Combination of performance-based mechanism and traditional regulation.

I Factor

An adjustment to the utility's revenue/rates reflecting the inflation.

Incentive Regulation

A method of regulation where the regulator uses explicit incentives to motivate utilities to improve efficiency or achieve other performance targets.

Incremental Capital Module

An adjustment that addresses the treatment of new capital investment.

Internal Benchmarking

A way of measuring a utility's performance against internal standards.

Multi-year Rate Plan

A plan used determining the rates the utility may charge for each year over a term, or regulatory cycle, of two years or more.

Opex

An ongoing cost generated from running a product, business, or system

Optional Tariffs

A provision of a menu of rate designs.

Performance Based Regulations

A regulatory approach that focuses on performance, results and outcomes.

Price Cap

A limit on the price that the utility can charge.

Productivity Stretch Factor

An additional percentage applied to the X factor that requires productivity gains in excess of the past performance.

Revenue Cap

A limit on the total revenue in a given period.

Off-ramp

A mechanism that allows, under certain conditions, the termination or modification of the plan before its end-of-term.

RIIO

Ofgem's new regulatory framework (Revenue = Incentives + Innovation + Outputs)

Service Target Performance Incentive Scheme

An incentive scheme designed to balance the incentive to reduce expenditure with the requirement to maintain and improve the quality of customer service.

Sliding-scale Regulation

A modification of a rate-of-return regulation where the regulators identifies a range of possible profit levels.

Total Factor Productivity

A measure of efficiency of utilization of all inputs.

Traditional Cost of Service Regulation

The traditional method used to regulate utility industries, where the regulator establishes the revenue requirement that reflects the total amount that utility needs to collect to cover its costs and earn a reasonable rate of return.

Transmission

The process of moving electricity from generators to distribution networks.

X Factor

An adjustment to revenue/rates reflecting anticipated changes in terms of productivity.

Yardstick Competition

A regulatory instrument used to simulate competition by comparing performance across companies..

Z Factor

An adjustment to revenue/rates in order to recover extraordinary costs that utilities cannot control or anticipate.

LIST OF ACRONYMS

ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
AEUB	Alberta Energy and Utilities Board
AUC	Alberta Utilities Commission
AWE	Average Weekly Earnings
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CAPEX	Capital Expenditure
CCA	Consumers' Coalition of Alberta
CCG	Consumer Challenge Group
CENS	Cost of Energy Not Supplied
CESS	Capital Expenditure Sharing Scheme
COS	Cost of Service
CPI	Consumer Price Index
CSPM	Customer Service Performance Mechanism
CTAIDI	Customer Total Average Interruption Duration Index
DEA	Data Envelopment Analysis
DER	Distributed Energy Resources
DORC	Depreciated Optimized Replacement Cost
DSM	Demand Side Management
E3GRID2012	European TSO Benchmarking Study

EBSS	Efficiency Benefit Sharing Scheme
ECM	Efficiency Carry-Over Mechanism
ENMAX	ENMAX Power Corporation
ERAM	Electric Revenue Adjustment Mechanism
EUCPI	Electricity Utility Construction Price Index
ESM	Earnings Sharing Mechanism
FASIT	Standard Reporting System for Faults and Interruptions
FBR	Formula-Based Ratemaking
HV	High Voltage
ICM	Incremental Capital Module
IPI	Input Price Index
IR	Incentive Regulation
IQI	Information Quality Incentive
LDC	Local Distribution Company
MAR	Maximum Allowable Revenue
NARUC	National Association of Regulatory Utility Commissioners
NEC	National Electricity Code
NEM	National Energy Market
NER	National Electricity Rules
NERA	NERA Economic Consulting
NSW	New South Wales
NVE	Norwegian Water Resources and Energy Directorate
NYPSC	New York Public Service Commission
OEB	Ontario Energy Board
OFGEM	Office of Gas and Electricity Markets

O&M	Operating and Maintenance Cost
OPEX	Operating Expenditures
PEG	Pacific Economics Group
PBR	Performance Based Regulation
RAB	Regulated Asset Base
RB-ROR	Rate-Base Rate-of-Return
ROE	Return on Equity
RPI	Retail Price Index
RRFE	Renewed Regulatory Framework for Electricity Distributors
RRIO	Revenue Set to Deliver Strong Incentives, Innovation and Outputs
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STPIS	Service Target Performance Incentive Scheme
TFP	Total Factor Productivity
TOTEX	Total Expenditure
TSO	Transmission System Operator
UCA	Utilities Consumer Advocate
WACC	Weighted Average Cost of Capital
X factor	Efficiency Factor
Z factor	Exogenous Factor