Réponse d'Énergir, s.e.c. (Énergir) à la Demande de renseignements #1 de la FCEI

DEMANDE D'APPROBATION DU PLAN D'APPROVISIONNEMENT ET DE MODIFICATION DES CONDITIONS DE SERVICE ET TARIF D'ÉNERGIR, S.E.C., À COMPTER DU 1ER OCTOBRE 2019

DOSSIER R-4076-2018

PROPOSITION D'UN MODE DE RÉGLEMENTATION ALLÉGÉ

Question 1 :

Références:

(i) B-0006, p. 13, notes de bas de page 16 et 17
(ii) B-0006, p. 11

Préambule :

(i)
Pacific Economics Group Research, LLC (2016), Alberta Utility Commission, pièce 20414-X0082, p. 64, Tableau 5a

PEG (2017), préparé pour Public Utility Commission du Colorado, Attachment MNL-2, p. 25 de 46, Table 2

« Dépenses d'exploitation autorisées en fonction de la croissance réelle des clients constatée au rapport annuel et de la croissance du niveau des prix (inflation) selon des indices externes au distributeur. »

Questions :

1.1 Veuillez fournir les deux études complètes mentionnées au préambule i).

Réponse :

Veuillez vous référer aux annexes Q-1.1a) et Q-1.1b) de la présente réponse.

1.2 Veuillez fournir pour les années 2009 à 2018, le nombre de clients en début d'année, le nombre de clients en fin d'année, les ajouts bruts de clients, les pertes de clients et les ajouts nets de clients.

Réponse:

Énergir réfère l'intervenant au dossier R-3867-2013, phase 3B, pièce B-0406, réponse à la question 11.1. En effet, cette demande de renseignement de la Régie concernait l'évolution du nombre de clients, des pertes de clients et des nouveaux clients, et ce, par marché et par tarif.

À noter qu'Énergir réitère qu'il peut exister certains enjeux dans l'arrimage des différentes informations et que la dénomination de client est sujette à différentes définitions; soit qu'il s'agit d'un contrat ou d'une installation. Également, les différents systèmes d'information actuels d'Énergir ne permettent pas toujours de communiquer entre eux ni de retracer toute l'information de la consommation de la clientèle. La tâche afin de consolider l'information et d'en faire l'adéquation est donc ardue. Voici d'ailleurs quelques mises en garde énoncées à la réponse 11.1 du dossier R-3867-2013, phase 3B, pièce B-0406 :

- Le nombre de clients, selon la définition d'Énergir, pour une année est le nombre moyen de contrats actifs sur une période de 12 mois. Chaque contrat actif lors d'un mois équivaut donc à 1/12^{e} de client.
- La perte d'un contrat ne signifie pas nécessairement la perte d'un client. Un contrat peut devenir caduc de par un changement contractuel, notamment par une nouvelle entente tarifaire ou par un changement de dénomination sociale. Un contrat peut également être terminé par un changement de responsabilité, notamment lors d'un déménagement suivi d'un réaménagement. Dans les deux cas, cela a un effet neutre sur le nombre de clients ou les volumes et Énergir ne les considère ni comme des pertes ni comme de nouveaux clients.
- L'évaluation des pertes de clients est une méthodologie nouvellement développée à la demande de la Régie lors de la Cause tarifaire 2013. Le statut d'une perte de client se matérialise après avoir constaté 12 mois d'inactivité de suite sans facture. Il y a donc toujours un délai entre le statut de perte de client et le suivi du nombre de clients comptabilisé en 1/12^{e}. Également, une perte peut être compensée par un nouvel aménagement au-delà du 12^{e} mois qui ne sera généralement pas capté comme un nouveau client (nouvelle vente) puisque ce dernier ne nécessitera habituellement pas de nouveaux investissements. Lors de la Cause tarifaire 2017, Énergir avait d'ailleurs répondu à la réponse 12.16 de la demande de renseignements n^{o} 2 de la FCEI (R-3970-2016, B-0187, Gaz Métro-14, Document 4) que près de 1 400 installations devenues inactives entre 2013 et 2015 étaient redevenues actives depuis. À la réponse à la question suivante, il était également mentionné qu'environ 90 % de ces installations ne nécessitaient aucun investissement et n'étaient ainsi pas considérées comme une nouvelle vente. Enfin, Énergir aimerait rappeler qu'elle ne dispose pas d'historique de pertes antérieures à 2013 tel qu'expliqué dans sa pièce R-3837-2013, Gaz Métro-7, Document 3. D'ailleurs dans sa décision D-2014-077, la Régie s'était montrée satisfaite des efforts réalisés par Énergir afin de réconcilier l'information :

> « *[131] Compte tenu de l'absence de données historiques valables, la Régie constate qu'il n'y a pas lieu de poursuivre les efforts pour retracer les informations sur les clients perdus pour les années antérieures à 2013. Elle est toutefois d'avis qu'il est important de mettre en place un suivi systématique permettant de connaître le nombre et les caractéristiques des clients perdus à chaque année.*

- Les nouveaux clients tel que présenté au plan de développement représentent le nombre de ventes signées dans l'année qui nécessitent des investissements et non leur mise en service. Comme il existe toujours un délai entre la signature d'un contrat et la mise en service, les nouveaux clients signés ne s'arriment également pas parfaitement avec l'évolution du nombre de clients.

Malgré les difficultés d'adéquation des différentes informations entre elles, Énergir a recensé plusieurs informations jugées pertinentes en réponse à la question 11.1 du dossier R-3867-2013, phase 3B, pièce B-0406. Elle invite l'intervenant à les consulter.

1.3 Veuillez ventiler l'information produite en 1.2 selon les catégories de clients (résidentiels, CII, VGE).

Réponse:

Veuillez vous référer à la réponse de la question 1.2.

Next Generation PBR for Alberta Energy Distributors

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23 March 2016

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1. Introduction

Most Alberta gas and electric power distributors operate under multiyear rate plans, a popular form of Performance Based Regulation ("PBR").[1] In May 2015, the Alberta Utilities Commission ("AUC") issued Bulletin 2015-10 initiating a generic proceeding (since enumerated as Proceeding 20414) to establish parameters for the next generation of PBR for these utilities.[2] In an August 21 letter the Commission released a Final Issues List for the proceeding.[3] The main issues to be considered are rebasing and the going-in rates for 2018; the X factor; and the treatment of capital cost.

Pacific Economics Group Research ("PEG Research") LLC is the leading North American consultancy on multiyear rate plans for gas and electric utilities. Work for diverse clients that includes regulators, utilities, and consumer groups has given our practice a reputation for objectivity and dedication to good regulation. We have played a prominent role in PBR proceedings in Alberta, British Columbia, Ontario, and Québec. The Consumers' Coalition of Alberta ("CCA") has retained us to prepare testimony on the issues in this proceeding.

Our testimony begins with some background on PBR in Alberta that is pertinent to our analysis and recommendations. There follow extensive discussions of the capital tracker, X factor, and rebasing issues. An Appendix provides some details of our research.

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[1] ENMAX, the power distributor in Calgary, is currently between plans.

[2] AUC, *Generic Proceeding to Establish Parameters for the Next Generation of Performance-based Regulation Plans,* Proceeding 20414, Bulletin 2015-10, May 2015.

[3] AUC, *Generic Proceeding to Establish Parameters for the Next Generation of Performance-based Regulation Plans,* Proceeding 20414, Final Issues List, August 2015.

2. Background

2.1. First Generic PBR Proceeding

Overview

In its September 2012 decision in Proceeding 566 (D.2012-237), the AUC established a first-generation system of PBR that applies to most provincial energy distributors.[4] In the approved system, multiyear rate plans feature formulaic "I-X" attrition relief mechanisms which are based on index research and escalate rates of power distributors and revenue requirements (aka allowed revenues) of gas distributors. The X factors in the indexing formulas of all utilities are the sum of a 0.96% estimate of the long-term trend in the multifactor productivity ("MFP") of U.S. power distributors and a 0.20% "stretch factor." The 0.96% productivity estimate was prepared by National Economic Research Associates.

The plans permit utilities to request supplemental revenue from "capital (cost) tracker mechanisms" to fund "necessary" capital expenditures ("capex").[5] Percentage changes in rates (or revenue) due to the operation of these trackers are called "K factors." Earnings sharing mechanisms were not approved. Efficiency carryover mechanisms ("ECMs") permit utilities to keep some benefits of high earnings achieved for a few years after their expiration.

X Factor

The Commission made a number of statements about X factors that bear repeating as the methodology for setting X is reconsidered.

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[4] AUC, *Rate Regulation Initiative: Distribution Performance-Based Regulation*, Decision 2012-237, September 2012.

[5] The exact form of the tracker was left to be determined.

- "NERA's TFP estimate of 0.96 per cent represents a reasonable starting point for setting an X factor for the Alberta companies."[6]
- "The Commission's preferred method of dealing with companies' concerns regarding unusual capital expenditures is through the use of capital trackers. The Commission acknowledges that, in theory, because capital expenses subject to these trackers will not be subject to the I-X mechanism, NERA's TFP number may need to be adjusted."[7] However, no adjustment was made because there was conflicting evidence on the proper direction of the adjustment.
- In its determination of capital trackers, the Commission states repeatedly in D. 2013-435 that customers are guaranteed the benefits of the X factor. On p. 37, for example, the Commission states that "customers will benefit from the expected productivity gain embedded in X whether or not it is achieved."[8]
- The AUC rejected the idea of company-specific stretch factors based on statistical benchmarking, stating on p. 100 of its decision that "the Commission does not wish to engage in this type of analysis for the purposes of PBR because of the practical and theoretical problems associated with comparing efficiency levels among companies."[9]

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[6] AUC Decision 2012-237, *op. cit.,* p. 86.

[7] AUC Decision 2012-237, *op. cit.*, p. 97. The Commission stated in its December 2013 capital tracker application decision that "The long term productivity measure used TFP growth of the distribution utility industry. This TFP growth was based on a study that comprised all capital investments undertaken by the companies in the study over the period measured and captures year-to-year fluctuations in the need for capital." (p. 31)

[8] EPCOR similarly stated that "the gains to consumers are guaranteed to them independent of the actual performance of the utilities" [EPCOR Reply Argument in Proceeding 2131, p. 15, paragraph 44].

[9] AUC Decision 2012-237, *op. cit.,* p. 100.

Capital Trackers

Tracker treatment is available on a case by case basis for capex projects meeting certain eligibility requirements. The Commission established the following eligibility requirements on page 126 of D. 2012-237.

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.

The Commission clarified that Criterion 2

> excludes projects required to accommodate customer or demand growth because a certain amount of capital growth is expected to occur as the system grows and system growth generates new sources of revenue that offset the costs of the new capital. The new sources of revenue can come in the form of increased customers and load growth, and also through contributions in aid of construction.[10]

Capex eligible for tracker treatment must also exceed a materiality threshold. The Commission described these eligibility requirements as having a "targeted criteria-based nature" that "limits the number of projects that are outside the I-X mechanism, and as a result, the incentive properties of PBR are preserved to the greatest extent possible."[11]

The evidentiary requirements established in D. 2012-237 were fairly extensive.

> The company must demonstrate that the capital expenditures are required to prevent deterioration in service quality and safety, and that service quality and safety cannot be maintained by continuing with O&M and capital spending at levels that are not substantially different from historic levels. The company will

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[10] AUC Decision 2012-237, *op. cit.,* p. 127.

[11] *Ibid*., p. 124.

> also be required to demonstrate that the capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program."[12]

K factors may initially be based on capex forecasts but are subject to a true up to the prudently-incurred actual capex.[13] 100% of capex underspends are passed through to customers in these true ups.

Some alternative means of funding capex surges that had been proposed in the proceeding were rejected.

- ATCO witness Carpenter had proposed using the trend in the plant value of utilities in Dr. Makholm's TFP sample as the point of comparison to avoid double counting.[14]
- ATCO proposed fixing K at an amount that covers the forecasted growth in a company's total capital cost.[15]
- CCA proposed tracking tracked capex in subsequent plans. However, the Commission stated that it "accepts the arguments that the complexity of isolating certain capital expenditures in perpetuity beyond the PBR term outweighs the benefits. … Therefore, the Commission requires that the revenue requirement impact of the capital tracker expenditures be recorded outside of the I-X mechanism only during the course of the current PBR term.[16]

The Commission also acknowledged some potential hazards of capital trackers in D. 2012-237.

[12] *Ibid.,* p. 126.

[13] *Ibid.,* p. 131.

[14] *Ibid.,* p. 118.

[15] *Ibid.,* p. 131.

[16] *Ibid.,* p. 129.

- “A capital factor must be carefully designed in order to maintain the efficiency incentives of PBR, and also to avoid double-counting.”[17]
- "The use of long term forecasts as proposed by ATCO Electric for its K factor does create some efficiency incentives. However, in the absence of a true-up, the Commission considers the incentives for a company to exaggerate its capital needs…to be a major drawback to such an approach."[18]
- "The Commission recognizes that superior efficiency incentives would be created if the companies were required to make capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker."[19]

Efficiency Carryover Mechanisms

The Commission supported the general idea of an ECM, stating that “ECMs are an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects.”[20] It approved ECMs that permitted utilities to keep a share of any surplus earnings achieved during the plan for 2 years after its expiration.

Reopeners

The Commission ruled “that any party, including the Commission on its own motion, will be permitted to bring an application to re-open and review a PBR plan.”[21] Parties can request a

[17] *Ibid.,* p. 115.

[18] *Ibid.,* p. 131.

[19] *Ibid.*

[20] *Ibid.,* p. 169.

[21] *Ibid.,* p. 157.

reopener if the ROE varies by more than 300 basis points for two consecutive years or by 500 basis points in any one year.[22]

2.2. Capital Tracker Application Proceeding

In the first capital tracker application proceeding, which concluded in December 2013 (D.2013-435), the AUC considered how its eligibility criteria should be interpreted and applied to projects the companies proposed for tracker treatment for the first year of PBR.[23] The Commission adopted a *quantitative* method for containing double counting. That portion of the annual capital cost of certain projects is eligible for tracker treatment in a given year that is "in excess of the revenue available from the I-X mechanism... The Commission will refer to this comparison of revenues as the 'accounting test.' "[24] More specifically, the Commission adopted a "project net cost approach" to the accounting test that is similar to the approaches that had been proposed by EPCOR and AltaGas. In the Commission's words,

> in order to calculate the amount of an investment that can be considered outside the normal course of the company's ongoing operations and to be recovered by way of capital trackers, it is necessary to compare the forecast revenue requirement for a project to the going-in revenue requirement that is historically associated with a similar type of capital expenditure escalated by I-X and including the impact on revenue of any changes in billing determinants.[25]

EPCOR proposed to apply the accounting test to projects with capital costs growing more *slowly* than I-X revenue --- thereby reducing the K factor --- as well as costs growing more

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[22] *Ibid.,* p. 161.

[23] Since the ruling was issued late in the year, it essentially addressed the ratemaking treatment of plant additions that had already been made.

[24] AUC, *Distribution Performance-Based Regulation 2013 Capital Tracker Applications*, D. 2013-435, December 2013, pp. 37-38.

[25] *Ibid.,* p. 53.

rapidly. However, negative K factor adjustments (as they were termed by EPCOR) were prohibited by the AUC on the grounds that these would weaken performance incentives.[26]

The Commission rejected CCA's proposal to make the accounting test for power distributors reflect the fact that the *capital* productivity of U.S. power distributors has tended to grow more slowly than the *total factor* productivity. This would require estimates of *partial* factor productivity ("PFP") trends. Neither did the Commission acknowledge that electric utilities would thereby effectively be overcompensated for their O&M expenses. Use of PFP results had been rejected in D. 2012-237, and in D. 2013-435 the Commission refused to reconsider its decision.[27]

With respect to growth-related capex the Commission revised its previous stance to rule that growth-related capex projects (and, basically, all projects) are potentially eligible for tracker treatment if they are expected to be materially underfunded in a given year. CCA had argued that utilities with large growth projects also tended to experience outsized scale economies that accelerate their productivity growth. The AUC stated that "the Commission agrees with [EPCOR witness] Dr. Weisman's assessment that the extent of the economies of scale (one potential driver of intertemporal double-counting) is 'unknown and perhaps unknowable' at this time."[28] Further, "any economies of scale and resulting gains are already reflected in the PBR plans on a prospective basis through the X factor… Incorporating these productivity gains above the Commission-approved X factor in the calculation of capital tracker amounts will effectively result in revisiting the 'fixed-price contract' that is a PBR plan."[29] More

[26] *Ibid*., p. 197.

[27] Productivity witness Makholm did not report partial factor productivity results in his generic proceeding evidence and then argued as a witness for ATCO in the capital tracker proceeding that they could not be produced from his evidence.

[28] AUC Decision 2013-435, *op. cit.,* p. 55.

[29] *Ibid.,* p. 56.

generally, the Commission ruled that "Any long-term productivity gains above those prescribed by the parameters of the approved PBR plans, and which may give rise to concerns with intertemporal double-counting, will be passed on to customers at the time of any rebasing."[30]

A 40 basis point *cumulative* materiality threshold on projects eligible for tracking was approved. A 4 basis point threshold was applied to individual projects.

2.3. 2015 Generic PBR Proceeding

The August 21 letter on the final issues list had some noteworthy highlights.

- The Commission seems open to the idea of not holding rate cases at the conclusion of the current plan, noting the upside that "the regulatory burden to complete the rebasing may be reduced, the perverse incentives of rate base rate of return applications may be minimized and the incentive properties of the PBR plan may be enhanced."[31]
- Another rebasing issue on the final list is "How should the efficiency carryover mechanism approved in the first generation PBR plans be incorporated into the rebasing process or next generation PBR plans?"[32] It is unclear whether the AUC wishes in this proceeding to consider the appropriate ECM for next-generation PBR as well as the implementation of the ECM from first-generation PBR.
- The Commission indicated a willingness to reconsider stretch factors.
- The Commission indicated special concern about the treatment of capital cost, stating that "finding a mechanism that achieves the balance between providing incremental

[30] *Ibid*.

[31] AUC, Final Issues List, *op cit.,* p. 6.

[32] *Ibid*., p. 11.

funding for capital while maintaining the incentives to improve productivity and lower costs inherent in the PBR plans, without double counting, has been challenging during the first PBR term."[33] It asks "are there alternatives to the capital tracker mechanism available that will provide the necessary funding while increasing regulatory efficiency during the next generation PBR term, while creating stronger incentives for companies to achieve efficiencies."[34]

- In discussing possible alternative ratemaking treatments for capital, the Commission opened the door to reconsidering approaches it rejected in prior proceedings.[35]
- With respect to other provisions of the current plan, the AUC states that "the Commission will not undertake an assessment of the success of all of the various provisions of the existing PBR plans, nor will it consider a restructuring of a majority of the components of the plans at this time… any such review process will be initiated at a later date."[36]

<u>Sappington and Weisman Paper</u>

Dennis Weisman and David Sappington have written a white paper for EPCOR on alternative ratemaking treatments for capital in next-generation PBR.[37] They identify three approaches as being particularly promising.

IIIC: PRICE CAPS WITH CAPITAL TRACKERS AND ASSOCIATED K FACTORS

This is basically the approach the Commission adopted in D. 2012-237.

[33] *Ibid.*, p. 9.

[34] *Ibid.*, p. 11.

[35] *Ibid.*, pp. 11-12.

[36] *Ibid.,* p. 4.

[37] David E. M. Sappington and Dennis L. Weisman, *Assessing the Treatment of Capital Expenditures in Performance-Based Regulation Plans,* September 2015.

IIIE: Price Caps with an F Factor (“K-Bar”) Adjustment

A forward-looking “F factor” is added to the I-X mechanism that provides supplemental capital revenue, the need for which is identified at the start of the plan. A capital tracker is still available for unforeseen capex needs that arise during the plan.

IIIF: Price Caps with Limited Factor Adjustments and a Midterm Review

This approach is similar to IIIE but would add a midterm adjustment of the K factor and not permit supplemental capital trackers.

3. Capital Cost

3.1. Analysis

In Alberta's current PBR system we have seen that growth in the revenue that addresses a utility's capital cost is determined by the I-X mechanism, with the exception that revenue is increased as needed to ensure that the annual cost of no kind of capital grows materially *faster* than I-X escalation *in a particular year*. No analogous revenue adjustment is guaranteed when any cost addressed by indexing, including the annual cost of the same capex in later years, grows more *slowly* than I-X escalation. The X factor is based on the long-run trend in the MFP of a national sample of U.S. power distributors.

The capital tracker provisions have adverse consequences for customers. Customers are no longer guaranteed the full benefit of the peer group's MFP growth, even in the longer run. Customers receive the benefit of the peer group MFP trend only in the narrow sense that growth in the components of revenue *that address certain costs* are slowed by the trend. When the capital tracker is operative, the growth in total utility revenue reflects MFP growth that can be far below the peer group trend.

This outcome might be satisfactory if trackers cost-effectively provide utilities with the minimum extra revenue needed to fund efficient capex. Unfortunately, this is not the expected outcome. One problem is that the capital tracker tends to overcompensate the utility for high capex.[38] Another is that the tracker weakens the incentive for capex containment. A third is that the regulatory cost of the tracker is fairly high. We provide extended discussions of the first two problems in the next two subsections.

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[38] AUC decisions speak at some length of a "double counting" problem. We prefer the term "overcompensation" since the problem may extend beyond double counting.

Overcompensation

The capital tracker ensures that no component of a utility's capital cost grows materially faster than the corresponding allowed revenue in a given year. An overcompensation problem arises if this is more money than the utility needs to address the potential attrition. Since revenue matches capital cost exactly in the targeted area, this will be true if the I-X mechanism overcompensates the utility for growth in its *other* costs, including the declining future cost of the capex that is temporarily eligible for tracking. We define overcompensation as a tendency for revenue escalation to exceed that required by a normal utility in the management of other costs. Utilities can use this extra revenue to finance a portion of their capex surges. The mathematical reasoning behind this result is detailed in Appendix Section A.1. Overcompensation can occur in years when trackers are operative and in years when they are not.

While overcompensation for other costs may seem irrelevant in the design of a capital tracker, it must be remembered that there is no principle of regulation that the component of a utility's revenue that corresponds to a particular cost must equal that cost each year. In fact, the revenue that a particular capital project gives rise to often differs from the corresponding cost under various regulatory systems. Making the utility whole for a temporary inadequacy in the revenue corresponding to a particular cost is not then self-evidently reasonable.

To understand why overcompensation can occur under the current system, consider first that most capex scheduled for tracker treatment in Alberta is of the same kinds incurred by the U.S. power distributors sampled in NERA's productivity study. This capex slowed growth in the MFP of sampled distributors, thereby lowering the X factor that the AUC approved and quickening the pace of allowed revenue escalation. In our 2013 testimony for the Commercial Energy Consumers ("CEC") of British Columbia, we showed that the productivity trend of U.S. power distributors is considerably higher if a portion of their capex is excluded. Similar results are obtained in our new study, as we discuss further below.

Consider next that a utility's productivity growth is buffeted by random events that cause it to be well below the long-run industry trend in some years and above it in others. The long-run productivity trend of the peer group which was used to calibrate X reflects events of both kinds. For example, the sample used in our new study for the CCA includes several utilities that experienced slow productivity growth due to hurricanes. When supplemental revenue is offered only for random events that *slow* capital productivity growth, however, I-X becomes the revenue cap only for capital costs incurred under neutral or favorable conditions.

Suppose, for example, that a power distributor must occasionally build a new substation due to transmission line construction. The capex for all such projects undertaken by sampled distributors is reflected in their long-run MFP trends. If the cost of these substations is tracked in the years when they are built, the I-X mechanism tends to apply to costs of Alberta utilities in periods when these kinds of projects are not needed.

It is possible, of course, that the utility could experience an inordinately large number of (or inordinately large) unfavorable events that make it difficult to achieve the MFP trend of the peer group in the short run or long run. For example, a distributor directly hit by a hurricane may deserve supplemental compensation even though a few utilities in the productivity sample used to calibrate X have been similarly afflicted. A utility ordered to replace all wooden poles with cement poles could, similarly, argue that this has rarely been asked of peer group utilities. However, the degree to which peer group productivity trends reflect various kinds of unfavorable events is difficult to assess.

It should also be noted that, whereas utilities can receive extra revenue for rapid capital growth from a wide range of external causes, the Commission has not elected to adjust X for business conditions in Alberta that tend to encourage more rapid productivity growth. For example, despite the recent slowdown in economic growth, brisk demand growth is likely to continue. While this increases the opportunity to bolster productivity growth through the realization of scale economies. The X factor in first-generation PBR is based on the productivity trend of utilities experiencing only *average* growth in demand.

Another problem is that high capex today tends to reduce the need for revenue growth in other periods.

- A capex surge tends to slow subsequent cost growth as the resulting "lump" of plant value depreciates.
- A "bunching" of conventional capex can reduce the need for such capex before and after it occurs.
- Capex can accelerate growth in O&M productivity. Capex for AMI and system undergrounding are power distribution examples of this phenomenon.[39]
- Growth-related projects are partially funded by customer contributions and give rise to other additional revenue. For Alberta power distributors, the new revenue comes from growth in billing determinants. For gas distributors, new revenue comes from the customer term of the revenue per customer index.

Note that while a capex surge, and the resultant short-term productivity *slowdown* and revenue shortfall are easily discerned, normal productivity growth modestly in *excess* of the peer group norm that may precede or follow the surge for many years may not be recognized. The AUC seems to have accepted the importance of intertemporal considerations in the case of O&M expenses, since these expenses are characteristically volatile and will be well above O&M revenue in some years and well below it in others.

Overcompensation can also occur in years when the capital tracker is operational. A random event boosting the need for one kind of capital (e.g., a highly localized storm, flood, or forest fire) may coincide with other random events that reduce cost. There may be a chronic tendency for productivity growth of one kind of capital to be unusually slow. High capex for

[39] An example closer to the reader's home is that a motorist expects to cut her car repair bills when she buys a new car.

one kind of capital may be part of a strategy to reduce the cost of other inputs. It is thus possible for a utility experiencing slow productivity growth in one kind of capital to nonetheless achieve normal multifactor productivity growth with normal effort.

The overcompensation problem is aggravated for power distributors. Under the currently broad eligibility guidelines for tracking capital cost, the I-X mechanism applies chiefly to O&M expenses. We showed in both our 2012 Alberta testimony and in 2013 CEC testimony that the O&M productivity of power distributors grows more briskly than their multifactor productivity. This finding is confirmed by our new research for the CCA, which is discussed in the next section. Thus, power distributors are provided more revenue for their O&M expenses under the current Alberta system than is needed to achieve normal O&M productivity growth. This surplus is available to self-finance temporary capital revenue deficits.

The AUC has rejected several proposals to reduce overcompensation on the grounds that the proposed remedies raise regulatory cost and/or weaken performance incentives. However, there are several ways to address the overcompensation problem that do not have these shortcomings, as we discuss further below.

Simulation

To shed light on the overcompensation problem, we have developed a spreadsheet that simulates the outcome of a stylized regulatory system under different patterns of productivity growth. Results are presented in Table 1. We assume in all scenarios that a revenue cap index provides a utility annually with 3% revenue growth (2% for inflation less a 0.80% X factor plus 1.8% for customer growth). The 0.80% X factor is assumed to be an accurate estimate of the long-run MFP trend of the peer group, and does not include a stretch factor. There is a five year plan term, and the periodic rate cases use forward test years. The initial annual revenue requirement is $1 billion.

Table 1 Capital Tracker Illustration I: “Echo Effect”

Year	Plan	Stable Productivity Growth: MFP Growth	Stable Productivity Growth: Cost [A] ($ 000)	Stable Productivity Growth: Revenue Cap Index Revenue [B] ($ 000)	Stable Productivity Growth: Revenue Shortfall [C=A-B] ($ 000)	"Echo Effect", No Cost Tracker: MFP Growth	"Echo Effect", No Cost Tracker: Cost [A] ($ 000)	"Echo Effect", No Cost Tracker: Revenue Cap Index Revenue [B] ($ 000)	"Echo Effect", No Cost Tracker: Revenue Shortfall [C=A-B] ($ 000)	"Echo Effect", No Cost Tracker: Discount Factor[1]	"Echo Effect", No Cost Tracker: Discounted Revenue Shortfall ($ 000)	"Echo Effect", Asymmetric Cost Tracker: Cost [A] ($ 000)	"Echo Effect", Asymmetric Cost Tracker: Revenue Cap Index Revenue [B] ($ 000)	"Echo Effect", Asymmetric Cost Tracker: Initial Revenue Shortfall ($ 000)	"Echo Effect", Asymmetric Cost Tracker: Supplemental Tracker Revenue [C] ($ 000)	"Echo Effect", Asymmetric Cost Tracker: Post-Tracker Revenue Shortfall [D=A-(B+C)] ($ 000)	"Echo Effect", Asymmetric Cost Tracker: Discounted Revenue Shortfall ($ 000)
										1.000							
2018	1	NA	$ 1,000,000	$ 1,000,000	$ -	NA	$ 1,000,000	$ 1,000,000	$ -	0.935	$ -	$ 1,000,000	$ 1,000,000	$ -	$ -	$ -	$ -
2019	1	0.800	$ 1,030,455	$ 1,030,455	$ -	-3.000	$ 1,070,365	$ 1,030,455	$ 39,911	0.874	$ 34,891	$ 1,070,365	$ 1,030,455	$ 39,911	$ 39,911	$ -	$ -
2020	1	0.800	$ 1,061,837	$ 1,061,837	$ -	-3.000	$ 1,145,682	$ 1,061,837	$ 83,845	0.817	$ 68,535	$ 1,145,682	$ 1,061,837	$ 83,845	$ 83,845	$ -	$ -
2021	1	0.800	$ 1,094,174	$ 1,094,174	$ -	-3.000	$ 1,226,298	$ 1,094,174	$ 132,124	0.764	$ 100,978	$ 1,226,298	$ 1,094,174	$ 132,124	$ 132,124	$ -	$ -
2022	1	0.800	$ 1,127,497	$ 1,127,497	$ -	-3.000	$ 1,312,587	$ 1,127,497	$ 185,090	0.715	$ 132,264	$ 1,312,587	$ 1,127,497	$ 185,090	$ 185,090	$ -	$ -
2023	2	0.800	$ 1,161,834	$ 1,161,834	$ -	-3.000	$ 1,404,948	$ 1,404,948	$ -	0.668	$ -	$ 1,404,948	$ 1,404,948	$ -	$ -	$ -	$ -
2024	2	0.800	$ 1,197,217	$ 1,197,217	$ -	-3.000	$ 1,503,807	$ 1,447,735	$ 56,073	0.625	$ 35,029	$ 1,503,807	$ 1,447,735	$ 56,073	$ 56,073	$ -	$ -
2025	2	0.800	$ 1,233,678	$ 1,233,678	$ -	1.318	$ 1,541,596	$ 1,491,825	$ 49,771	0.584	$ 29,072	$ 1,541,596	$ 1,491,825	$ 49,771	$ 49,771	$ -	$ -
2026	2	0.800	$ 1,271,249	$ 1,271,249	$ -	1.318	$ 1,580,334	$ 1,537,258	$ 43,077	0.546	$ 23,526	$ 1,580,334	$ 1,537,258	$ 43,077	$ 43,077	$ -	$ -
2027	2	0.800	$ 1,309,964	$ 1,309,964	$ -	1.318	$ 1,620,046	$ 1,584,074	$ 35,972	0.511	$ 18,369	$ 1,620,046	$ 1,584,074	$ 35,972	$ 35,972	$ -	$ -
2028	3	0.800	$ 1,349,859	$ 1,349,859	$ -	1.318	$ 1,660,756	$ 1,660,756	$ -	0.477	$ -	$ 1,660,756	$ 1,660,756	$ -		$ -	$ -
2029	3	0.800	$ 1,390,968	$ 1,390,968	$ -	1.318	$ 1,702,488	$ 1,711,333	$ (8,845)	0.446	$ (3,948)	$ 1,702,488	$ 1,711,333	$ (8,845)		$ (8,845)	$ (3,948)
2030	3	0.800	$ 1,433,329	$ 1,433,329	$ -	1.318	$ 1,745,270	$ 1,763,451	$ (18,181)	0.417	$ (7,589)	$ 1,745,270	$ 1,763,451	$ (18,181)		$ (18,181)	$ (7,589)
2031	3	0.800	$ 1,476,981	$ 1,476,981	$ -	1.318	$ 1,789,126	$ 1,817,156	$ (28,030)	0.390	$ (10,939)	$ 1,789,126	$ 1,817,156	$ (28,030)		$ (28,030)	$ (10,939)
2032	3	0.800	$ 1,521,962	$ 1,521,962	$ -	1.318	$ 1,834,085	$ 1,872,497	$ (38,412)	0.365	$ (14,017)	$ 1,834,085	$ 1,872,497	$ (38,412)		$ (38,412)	$ (14,017)
2033	4	0.800	$ 1,568,312	$ 1,568,312	$ -	1.318	$ 1,880,173	$ 1,880,173	$ -	0.341	$ -	$ 1,880,173	$ 1,880,173	$ -		$ -	$ -
2034	4	0.800	$ 1,616,074	$ 1,616,074	$ -	1.318	$ 1,927,419	$ 1,937,432	$ (10,013)	0.319	$ (3,194)	$ 1,927,419	$ 1,937,432	$ (10,013)		$ (10,013)	$ (3,194)
2035	4	0.800	$ 1,665,291	$ 1,665,291	$ -	1.318	$ 1,975,853	$ 1,996,436	$ (20,583)	0.298	$ (6,139)	$ 1,975,853	$ 1,996,436	$ (20,583)		$ (20,583)	$ (6,139)
2036	4	0.800	$ 1,716,007	$ 1,716,007	$ -	1.318	$ 2,025,503	$ 2,057,237	$ (31,733)	0.279	$ (8,850)	$ 2,025,503	$ 2,057,237	$ (31,733)		$ (31,733)	$ (8,850)
2037	4	0.800	$ 1,768,267	$ 1,768,267	$ -	1.318	$ 2,076,402	$ 2,119,889	$ (43,487)	0.261	$ (11,340)	$ 2,076,402	$ 2,119,889	$ (43,487)		$ (43,487)	$ (11,340)
2038	5	0.800	$ 1,822,119	$ 1,822,119	$ -	1.318	$ 2,128,579	$ 2,128,579	$ -	0.244	$ -	$ 2,128,579	$ 2,128,579	$ -		$ -	$ -
2039	5	0.800	$ 1,877,611	$ 1,877,611	$ -	1.318	$ 2,182,067	$ 2,193,404	$ (11,336)	0.228	$ (2,584)	$ 2,182,067	$ 2,193,404	$ (11,336)		$ (11,336)	$ (2,584)
2040	5	0.800	$ 1,934,792	$ 1,934,792	$ -	1.318	$ 2,236,900	$ 2,260,203	$ (23,303)	0.213	$ (4,967)	$ 2,236,900	$ 2,260,203	$ (23,303)		$ (23,303)	$ (4,967)
2041	5	0.800	$ 1,993,716	$ 1,993,716	$ -	1.318	$ 2,293,110	$ 2,329,036	$ (35,926)	0.199	$ (7,160)	$ 2,293,110	$ 2,329,036	$ (35,926)		$ (35,926)	$ (7,160)
2042	5	0.800	$ 2,054,433	$ 2,054,433	$ -	1.318	$ 2,350,733	$ 2,399,966	$ (49,233)	0.186	$ (9,174)	$ 2,350,733	$ 2,399,966	$ (49,233)		$ (49,233)	$ (9,174)
2043	6	0.800	$ 2,117,000	$ 2,117,000	$ -	1.318	$ 2,409,804	$ 2,409,804	$ -	0.174	$ -	$ 2,409,804	$ 2,409,804	$ -		$ -	$ -
2044	6	0.800	$ 2,181,472	$ 2,181,472	$ -	1.318	$ 2,470,359	$ 2,483,194	$ (12,834)	0.163	$ (2,091)	$ 2,470,359	$ 2,483,194	$ (12,834)		$ (12,834)	$ (2,091)
2045	6	0.800	$ 2,247,908	$ 2,247,908	$ -	1.318	$ 2,532,436	$ 2,558,818	$ (26,382)	0.152	$ (4,018)	$ 2,532,436	$ 2,558,818	$ (26,382)		$ (26,382)	$ (4,018)
2046	6	0.800	$ 2,316,367	$ 2,316,367	$ -	1.318	$ 2,596,073	$ 2,636,746	$ (40,672)	0.142	$ (5,792)	$ 2,596,073	$ 2,636,746	$ (40,672)		$ (40,672)	$ (5,792)
2047	6	0.800	$ 2,386,911	$ 2,386,911	$ -	1.318	$ 2,661,309	$ 2,717,047	$ (55,737)	0.133	$ (7,422)	$ 2,661,309	$ 2,717,047	$ (55,737)		$ (55,737)	$ (7,422)
2048	7	0.800	$ 2,459,603	$ 2,459,603	$ -	1.318	$ 2,728,184	$ 2,728,184	$ -	0.124	$ -	$ 2,728,184	$ 2,728,184	$ -		$ -	$ -
2049	7	0.800	$ 2,534,509	$ 2,534,509	$ -	1.318	$ 2,796,740	$ 2,811,270	$ (14,530)	0.116	$ (1,691)	$ 2,796,740	$ 2,811,270	$ (14,530)		$ (14,530)	$ (1,691)
2050	7	0.800	$ 2,611,696	$ 2,611,696	$ -	1.318	$ 2,867,019	$ 2,896,886	$ (29,867)	0.109	$ (3,251)	$ 2,867,019	$ 2,896,886	$ (29,867)		$ (29,867)	$ (3,251)
2051	7	0.800	$ 2,691,234	$ 2,691,234	$ -	1.318	$ 2,939,063	$ 2,985,109	$ (46,046)	0.102	$ (4,686)	$ 2,939,063	$ 2,985,109	$ (46,046)		$ (46,046)	$ (4,686)
2052	7	0.800	$ 2,773,195	$ 2,773,195	$ -	1.318	$ 3,012,918	$ 3,076,019	$ (63,101)	0.095	$ (6,004)	$ 3,012,918	$ 3,076,019	$ (63,101)		$ (63,101)	$ (6,004)
2053	8	0.800	$ 2,857,651	$ 2,857,651	$ -	1.318	$ 3,088,629	$ 3,088,629	$ -	0.089	$ -	$ 3,088,629	$ 3,088,629	$ -		$ -	$ -
2054	8	0.800	$ 2,944,680	$ 2,944,680	$ -	1.318	$ 3,166,242	$ 3,182,692	$ (16,449)	0.083	$ (1,368)	$ 3,166,242	$ 3,182,692	$ (16,449)		$ (16,449)	$ (1,368)
2055	8	0.800	$ 3,034,358	$ 3,034,358	$ -	1.318	$ 3,245,806	$ 3,279,619	$ (33,813)	0.078	$ (2,630)	$ 3,245,806	$ 3,279,619	$ (33,813)		$ (33,813)	$ (2,630)
2056	8	0.800	$ 3,126,768	$ 3,126,768	$ -	1.318	$ 3,327,369	$ 3,379,498	$ (52,130)	0.073	$ (3,791)	$ 3,327,369	$ 3,379,498	$ (52,130)		$ (52,130)	$ (3,791)
2057	8	0.800	$ 3,221,993	$ 3,221,993	$ -	1.318	$ 3,410,981	$ 3,482,419	$ (71,438)	0.068	$ (4,857)	$ 3,410,981	$ 3,482,419	$ (71,438)		$ (71,438)	$ (4,857)
2058	9	0.800	$ 3,320,117	$ 3,320,117	$ -	1.318	$ 3,496,695	$ 3,496,695	$ -	0.064	$ -	$ 3,496,695	$ 3,496,695	$ -		$ -	$ -
2059	9	0.800	$ 3,421,230	$ 3,421,230	$ -	1.318	$ 3,584,562	$ 3,603,185	$ (18,623)	0.059	$ (1,107)	$ 3,584,562	$ 3,603,185	$ (18,623)		$ (18,623)	$ (1,107)
2060	9	0.800	$ 3,525,421	$ 3,525,421	$ -	1.318	$ 3,674,638	$ 3,712,918	$ (38,281)	0.056	$ (2,128)	$ 3,674,638	$ 3,712,918	$ (38,281)		$ (38,281)	$ (2,128)
2061	9	0.800	$ 3,632,787	$ 3,632,787	$ -	1.318	$ 3,766,977	$ 3,825,994	$ (59,017)	0.052	$ (3,067)	$ 3,766,977	$ 3,825,994	$ (59,017)		$ (59,017)	$ (3,067)
2062	9	0.800	$ 3,743,421	$ 3,743,421	$ -	1.318	$ 3,861,636	$ 3,942,512	$ (80,876)	0.049	$ (3,930)	$ 3,861,636	$ 3,942,512	$ (80,876)		$ (80,876)	$ (3,930)
2063	10	0.800	$ 3,857,426	$ 3,857,426	$ -	1.318	$ 3,958,674	$ 3,958,674	$ -	0.045	$ -	$ 3,958,674	$ 3,958,674	$ -		$ -	$ -
2064	10	0.800	$ 3,974,902	$ 3,974,902	$ -	1.318	$ 4,058,150	$ 4,079,233	$ (21,083)	0.042	$ (896)	$ 4,058,150	$ 4,079,233	$ (21,083)		$ (21,083)	$ (896)
2065	10	0.800	$ 4,095,955	$ 4,095,955	$ -	1.318	$ 4,160,126	$ 4,203,465	$ (43,338)	0.040	$ (1,721)	$ 4,160,126	$ 4,203,465	$ (43,338)		$ (43,338)	$ (1,721)
2066	10	0.800	$ 4,220,696	$ 4,220,696	$ -	1.318	$ 4,264,665	$ 4,331,479	$ (66,814)	0.037	$ (2,481)	$ 4,264,665	$ 4,331,479	$ (66,814)		$ (66,814)	$ (2,481)
2067	10	0.800	$ 4,349,235	$ 4,349,235	$ -	1.318	$ 4,371,831	$ 4,463,392	$ (91,562)	0.035	$ (3,179)	$ 4,371,831	$ 4,463,392	$ (91,562)		$ (91,562)	$ (3,179)
2068	11	0.800	$ 4,481,689	$ 4,481,689	$ -	1.318	$ 4,481,689	$ 4,481,689	$ -	0.032	$ -	$ 4,481,689	$ 4,481,689	$ -		$ -	$ -
Full Period Averages		**0.800**	**$ 2,329,526**	**$ 2,329,526**	**$ -**	**0.800**	**$ 2,551,896**	**$ 2,563,187**	**$ (11,291)**		**$ 5,621**	**$ 2,551,896**	**$ 2,563,187**	**$ (11,291)**	**$ 62,586**	**$ (23,562)**	**$ (3,059)**
Full Period Sums			**$ 118,805,851**	**$ 118,805,851**	**$ -**		**$ 130,146,703**	**$ 130,722,519**	**$ (575,816)**		**$ 286,655**	**$ 130,146,703**	**$ 130,722,519**	**$ (575,816)**	**$ 625,863**	**$ (1,201,679)**	**$ (156,009)**
Out Year Averages		**0.800**	**$ 2,320,256**	**$ 2,320,256**	**$ -**	**0.778**	**$ 2,547,714**	**$ 2,562,110**	**$ (14,395)**		**$ 7,166**	**$ 2,547,714**	**$ 2,562,110**	**$ (14,395)**	**$ 78,233**	**$ (30,042)**	**$ (3,900)**
Out Year Sums			**$ 92,810,241**	**$ 92,810,241**	**$ -**		**$ 101,908,572**	**$ 102,484,389**	**$ (575,816)**		**$ 286,655**	**$ 101,908,572**	**$ 102,484,389**	**$ (575,816)**	**$ 625,863**	**$ (1,201,679)**	**$ (156,009)**

[1] This discount factor series is calculated geometrically, rather than using a logarithmic growth rate.

Provided that the revenue cap index provides appropriate compensation for the cost impact of input price inflation and demand growth and that the utility achieves the 0.80% MFP trend of the peer group every year, the I-X mechanism is exactly compensatory between rate case years. Suppose, however, that although the utility achieves the long-run MFP trend over many years, an “echo effect” commences at the start of the first plan that causes high levels of conventional replacement capex for seven years. As a consequence of this capex surge, the utility experiences a 3% *decline* in its MFP through every year of the first plan and the first two years of the second plan. Because this echo effect involves a bunching of conventional capex, it reduces the need for capex in later years and should not prevent the utility from achieving the long-run MFP trend over a full replacement cycle. We assume that this cycle takes 50 years (or ten plans) due to a fifty year service life for the assets. Achieving the long-term MFP trend over ten plans requires MFP growth to average 1.32% annually in the years after the echo effect is finished.

In the middle panels of the table we consider what happens to the utility's finances under the echo effect if there is no capital tracker. It can be seen that the utility experiences revenue *shortfalls* in the indexing years of the first two plans that total about $626 million. It then experiences revenue *surpluses* in the out years of the next eight plans because the X factor reflects the *long-term* MFP growth trend and not the *accelerated* MFP growth trend that a normal utility would achieve in the aftermath of high echo effect capex. Over 10 plans, it can be seen that revenue surpluses substantially outweigh revenue shortfalls. However, assuming a 6.5% discount rate that is similar to the current weighted average cost of capital of Alberta energy distributors, there is a *discounted* revenue *shortfall* of about $287 million over the entirety of the investment cycle. The table thus shows that it can be unfair for a utility experiencing an echo effect at the start of PBR to operate without supplemental revenue in the early plans. However, the appropriate compensation is *roughly half* of the early revenue shortfall if X reflects the long-run MFP trend.

In the right-hand side of the panel we consider the consequences of making the utility whole for its early revenue shortfalls using asymmetric cost trackers that ignore later revenue surpluses. This is a stylized representation of the current ratemaking treatment in Alberta. It can be seen that although the utility is made whole for its early revenue shortfall it is nonetheless substantially overcompensated, receiving a discounted revenue surplus of $156 million. Furthermore, eliminating the early revenue shortfall clearly denies customers the benefits of the base productivity growth target in both the short and the long run. It is not enough for the utilities to receive the benefit of accelerated productivity growth in the periodic rate cases.

Incentives

To shed some light on the incentives for capex containment provided by Alberta's current PBR system we first consider the incentives under competitive market conditions and traditional regulation. The focus is on conventional replacement capex since this is a major category of tracked capex in Alberta and is relatively easy to analyze.

Competitive Markets In a competitive market, replacement capex is typically undertaken by an efficient firm because the expected net present value ("NPV") of the resultant annual costs (e.g., depreciation, taxes, and a return on net plant value) is exceeded by the expected NPV of system modernization benefits.[40] These benefits chiefly consist of the avoidance of undesirable consequences of advanced system age such as the following:

- rising operation and maintenance expenses
- rising discounts to customers due to diminished service quality
- increased margin losses due to reduced sales
- increased risk of safety problems.

The costs and benefits of capex occur over the service life of the assets and those in the future are discounted. Note that O&M cost savings play a key role in funding capex. There is no revenue "bump" from replacement capex.

Traditional Regulation Under traditional rate regulation, revenue is set roughly equal to the cost of service in periodic rate cases.[41] Rate cases occur at irregular intervals but, under contemporary business conditions, tend to be fairly frequent. There are typically no service quality performance incentive mechanisms ("PIMs") to penalize the utility for poor quality. However, poor quality can garner ill will from regulators, and outages produce margin losses.

[40] A competitive firm would also consider the capital gains from its investment.

[41] A portion of the cost may be disallowed in prudence reviews but this portion is typically small.

There is no revenue bump under traditional regulation for replacement capex until the next rate case. In the meantime the utility keeps O&M cost savings from the capex, but the annual capital cost that the capex gives rise to is high (since depreciation is just starting), and typically outweighs the benefits. The utility may therefore experience an initial revenue shortfall. Each future rate case establishes revenue for the asset that equals its annual cost in a test year, including a return on net plant value. While this creates an earnings stream, these rate cases also pass through to customers the savings from the O&M expenses that the capex achieved.

Base rates are fixed between rate cases, but the revenue associated with a particular capex project tends to grow with the (typically slow-trending) growth in billing determinants. Meanwhile, the annual cost of the capex tends to fall with depreciation. This gives rise to small profits from the asset between rate cases. A rate case thus initiates recovery of costs of recent capex but also gives back to customers the accumulating profits from depreciation of older plant.[42]

Hard Revenue Cap Consider next a multiyear rate plan with a revenue cap and no earnings sharing. Allowed revenue is set equal to cost in rate cases every five years. Between rate cases, allowed revenue is escalated by an "I-X" mechanism that is insensitive to the utility's actual cost. Service quality PIMs cause penalties if service quality worsens. The utility may be unable to recover margins lost due to outages.

Replacement capex produces no incremental revenue until the next rate case, and rate cases are less frequent than under traditional regulation. However, rate cases do occur periodically. These trigger a stream of revenue from capex but give back to customers the

[42] Note also that it makes sense under traditional regulation to bunch replacement capex around the time of the rate case in order to contain the upfront losses. Utilities have considerable discretion on the exact timing of this kind of capex.

benefit of any O&M cost savings that the capex achieved. Capex today produces more earnings between future rate cases than under traditional regulation since the component of revenue occasioned by the capex is escalated by the I-X mechanism for four years rather than being escalated only by growth in billing determinants for two or three years. A hard revenue cap can thus produce larger initial revenue shortfalls than traditional regulation but also produces larger revenue surpluses in later years. The utility can contain the initial revenue shortfalls by bunching capex in the years surrounding rate cases.

Revenue Cap + Alberta-Style Capital Tracker Suppose, now that we add an Alberta-style capital tracker to the PBR plan just described. The amount by which the cost of class j capex exceeds base capital revenue ("$RK_{j,0}$") escalated by I-X in a given year is eligible for capital tracker treatment. Supplemental revenue is later trued up to the actual cost ("$CK_{j,t}$"). Assuming no prudence disallowance, the supplemental revenue for each tracked class of capital j is then

$$Supplemental\ Revenue_{j,t} = CK_{j,t} - (I\text{-}X+g) \bullet RK_{j,0}.$$

The *total* revenue that addresses the cost of capital class j in period t is:

$$\begin{aligned} RK_{j,t} &= (I\text{-}X) \bullet RK_{j,0} + [CK_{j,t} - (I\text{-}X+g) \bullet RK_{j,0}] \\ &= CK_{j,t}. \end{aligned}$$

The revenue obtained for eligible projects thus closely tracks their cost when these costs are accorded tracker treatment. Furthermore, in securing tracker status the utility obtains implicit preapproval for capex projects. The initial revenue shortfall from a capex surge is eliminated but revenue surpluses occur thereafter between rate cases in four out of every five years. There is thus an expected overpayment for tracked capex that weakens the incentive to contain the capex.

Since many O&M expenses are ineligible for tracking, and there is no earnings sharing, the incentive to contain untracked expenses is, in contrast, relatively strong. There is thus an extra incentive to replace O&M inputs with capital. For example, there is an extra incentive to underground power distribution facilities.

It is also notable that utilities are incentivized to "bunch" capex so that it qualifies for tracker treatment. One reason that this is problematic is that regulators often have a hard time determining whether bunching is a cost-minimizing strategy. Utilities may request extra revenue for bunched capex of a certain kind at the same time that they are deferring capex of other kinds so that it can be bunched in future plans. Utilities also have an incentive to itemize costs artfully in the accounting tests so that they qualify for tracker treatment.

Incentives to exaggerate capex needs in regulatory proceedings should also be considered. The pass-through to customers of capex underspends under the current system reduces the incentive of utilities to exaggerate these needs. However, utilities still have an incentive to exaggerate capex needs so as to obtain the revenue bump and implicit project preapprovals that tracking produces. For example, they have an incentive to argue that capex must be bunched and not spread out in ways that would reduce extra revenue. Furthermore, utilities are unlikely to build into their forecasts of capex proposed for tracker treatment an appropriate allowance for accelerated productivity growth. Yet the current accounting test compensates them for the full amount by which the stretch factor raises X.

The incentive to exaggerate capex needs is even recognized by EPCOR's consultants Weisman and Sappington. They state, for example, with respect to their recommended option III.C (which is similar to the current system) that

> the plan may provide the company with an incentive to identify (and possibly exaggerate) "positive" capital trackers, but overlook (or understate the impact of) "negative" capital trackers.[43]

[43] Sappington and Weisman, *op. cit.,* p. 27.

It should also be noted that utilities are incentivized to oppose PBR provisions that reduce overcompensation. Even though capital trackers weaken capex containment incentives and tracker application proceedings are extremely time-consuming and controversial, utilities and their expert witnesses will argue that provisions to reduce overcompensation are unduly complicated and controversial and may weaken performance incentives. Even though capital trackers selectively compensate utilities for unfavorable business conditions, they will oppose adjustments to next generation PBR for favorable conditions, just as they did in the capital tracker application proceeding.

<u>Summary</u>

In summary, the ratemaking treatment of capex in Alberta's current PBR system materially weakens the capex containment incentives of energy distributors, reducing plan benefits available for sharing. The treatment is also unfair to consumers because utilities are overcompensated for their capex challenges. Utilities are fully compensated when growth in the cost of a particular kind of capital is temporarily rapid due to unfavorable conditions and held to a lenient productivity growth standard for costs subject to favorable conditions. Customers are not guaranteed the benefits of peer group MFP growth plus a stretch factor. Distributors have had high capex thus far under PBR, and it is fair to ask how much this reflects the peculiar incentive the tracker provides to bunch capex rather than cost-minimizing strategies. High capex in this plan should slow cost growth in the future, but utilities may be permitted to keep most of the resultant benefits.

The Commission selected its K factor approach as a way to strike a reasonable balance between regulatory cost, performance incentives, utility finances, and overcharging considerations. Yet the cost of regulating capital revenue is still high, capex containment incentives are still weak, and overcharging is still a problem. *Only the challenge to utility finances that high capex might occasionally pose has been effectively addressed.* Consumers may actually fare worse under this regulatory system than they would under a return to the previous regulatory regime. The impact is especially large for residential customers, for whom distribution charges loom largest as a percentage of the delivered cost of power.

This appears to be a classic case of "regulatory capture." The problems are so serious that mid-term adjustments to the current plan should be considered. At a minimum, ENMAX should not be permitted to operate under the current system in its interim PBR plan.

Need for Trackers

We conclude our analysis by discussing the need for capital trackers in next generation PBR. We believe that the need for capital trackers should eventually diminish in Alberta PBR plans, for several reasons.

1. Utilities will already have undertaken many years of high capex by the time that the next plan begins, in addition to the high capex of the prior decade. This should draw down the inventory of high capex projects.
2. Depreciation of recent high levels of plant additions will slow future distributor cost growth going forward.
3. [1] and [2] imply that capital productivity growth should accelerate in the future unless capex for some reason exceeds its recent high levels.
4. A high proportion of the capex approved for tracking resulted from the bunching of conventional capex.[44]
5. Growth in demand is expected to be fairly brisk, raising new revenue for old projects.
6. However, growth may be sufficiently slower than in the past to reduce the need for surges in growth-related capex.

[44] This statement is not meant to imply that all bunching was imprudent.

Utilities will nonetheless doubtless argue energetically about the continued need for capital trackers.

Capital Tracker Precedents

Capital cost trackers are widely used in the United States by gas and electric utilities. In gas distribution, they are particularly common for accelerated system modernization programs. Electric utilities use trackers for a variety of costs, including new generation, emissions control equipment, and advanced metering infrastructure ("AMI"). The need for trackers is heightened in the States by the fact that few utilities operate under multiyear rate plans, and many jurisdictions use historical test years in rate cases.

Incentivized capital trackers are used in several North American jurisdictions. These have taken the form of caps and sharing mechanisms. Caps may apply to each year of a capex project or to accumulated cost. They may apply to costs or rates. Some caps allow for recovery of amounts over the cap if the company can show that the amounts were prudently incurred. Alternatively, the caps may be hard, which provides a stronger incentive for a company to stay below them. Caps may be set at the approved budget level or incorporate contingencies for unexpected events. Floors may also be established, which allow companies to retain a portion of capex underspends.

Sharing mechanisms are based on the approved budget level and allow companies and customers to share in the benefits of underspending, the burdens of overspending, or both. These mechanisms may also have deadbands, around which the company receives 100% of the benefit of underspends or 100% of the burden of overspends.

One example of an incentivized capital cost tracker can be found in British Columbia. In order to receive a certificate of public convenience and necessity ("CPCN") for its Southern Crossing project, BC Gas (now FortisBC Energy) had to accept a hard cap of 110% of its forecasted cost and an incentive wherein it could recover all underspending below 90% of the approved forecast.

Table 2 provides details of a sampling of incentivized capital cost trackers. It can be seen that the use of caps is much more common than the use of sharing mechanisms. Caps are more often applied to costs than to rates.

Table 3 provides examples of trackers that require adjustments for O&M cost savings. It can be seen that these precedents have been used on several occasions in deployments of leak-prone gas main and service replacement programs and AMI deployments. These kinds of capex lead to easily definable O&M savings. The deployment of AMI reduces, if not eliminates, the need for meter readers, while the replacement of leak-prone gas mains and services should lead to a reduction in the need for leak surveys and repairs.

The use of caps, floors, sharing mechanisms, and the reduction of capital cost tracker revenue requirements for O&M savings have in a few instances been combined. For example, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Southern California Gas all have obtained special ratemaking treatments to recover the cost of full AMI deployment. Each approved AMI ratemaking treatment took the form of a capex tracker with a preapproved multiyear capex forecast. The deployment plans allowed recovery of capital costs with an offset for O&M savings.

If each company's actual cost to deploy AMI was in line with the approved forecast, there would be no subsequent prudence review. Diverse variance treatments were allowed for these plans. Southern California Edison's AMI deployment tracker featured an asymmetric sharing mechanism wherein 90% of the first $100 million in excess of the approved forecast was charged to ratepayers without the need for a further prudence review. Exceptions to the cost caps were made for *force majeure* events, changes in the project's scope due to government or regulatory activity, and delays in Commission approval. The treatment of variances from forecasted cost for San Diego Gas & Electric was similar, as 90% of the first $50 million over the budget would be granted to the Company without a further prudence review. The same exceptions to the cap as described for Southern California Edison applied to San

Table 2

Details of Incentivized Capital Cost Trackers

Jurisdiction	Company Name	Services	Name of Mechanism	Eligible Investments	Caps	Special Treatment of Cost Variances	Other Provisions	Case Reference
BC	Terasen Gas (now FortisBC Energy)	Gas	Not Applicable	Customer Care Enhancement Project	Hard cap	Deadband of +/- 10% of cap; Savings or costs beyond deadband split evenly between customer and company	Approval of Certificate of Public Convenience and Necessity ("CPCN") made conditional on sharing of variances	Order C-1-10
BC	Terasen Gas Vancouver Island (now FortisBC Energy)	Gas	Not Applicable	Gas pipeline lateral from Squamish to Whistler	Hard cap	Deadband of +/- 10% of cap; Savings or costs beyond deadband split evenly between customer and company	CPCN approval conditional on company acceptance of incentive mechanism. Incentive mechanism excludes costs of stream crossings. Budget amounts dependent upon final pipeline alignment choice	Order G-53-06
BC	Terasen Gas Whistler (now FortisBC Energy)	Gas	Not Applicable	Conversion of Whistler Gas system from propane to methane, meter/regulating station	Hard cap	Deadband of +/- 10% of cap; Savings or costs beyond deadband completely at company's risk	Budget amounts escalated for CPI growth	Order G-53-06
BC	BC Gas (now FortisBC Energy)	Gas	Not Applicable	Southern Crossing Pipeline Project	Hard cap	Deadband of +/- 10% of cap; Savings or costs beyond deadband completely at company's risk	Budget amounts escalated for CPI growth	Order G-51-99
BC	British Columbia Transmission Company	Power Transmission	Not Applicable	Vancouver Island Transmission Reinforcement Project	Cap and floor established using P90 (90% probability cost will not exceed) and P10 estimates expressed in nominal dollars.	Symmetric award/penalty of 25% of ROE component if cost is above P90 estimate or below P10 estimate	Monte Carlo analysis used to determine P90 and P10 estimates. Decision approving CPCN explicitly stated that incentive mechanisms have a much lower threshold than prudence tests	Order C-4-06
BC	FortisBC	Bundled power service	Not Applicable	Big White Supply Project	Hard cap	Deadband of +/- 10% of cap; Savings or costs beyond deadband completely at company's risk	Budget amounts escalated for CPI growth.	Order C-17-06
CA	Pacific Gas & Electric	Power Distribution	Cornerstone Improvement Project Balancing Account	Capital and O&M expenses to improve the reliability of the electric distribution system	Hard multiyear budget cap and year to year flexibility, but underspends returned to ratepayers	None	Reasonableness of costs can be reviewed when amounts enter base rates.	Decision 10-06-048 (June 2010)
CA	San Diego Gas & Electric	Power Distribution	Advanced Metering Infrastructure Balancing Account	Advanced metering infrastructure ("AMI")	Costs up to cap deemed ex ante prudent; exceptions to cap permitted based on force majeure events, changes in scope of project due to government or regulatory action, and delay in Commission approval.	No deadband. Asymmetrical mechanism wherein 90% of the first $50 million over the cap and 10% of first $50 million under the cap allocated to shareholders (No prudence review required)	Costs above cap and incentive mechanism may be recovered in rates following prudence review.	Decision 07-04-043 (April 2007)

Table 2 (cont'd)

Jurisdiction	Company Name	Services	Name of Mechanism	Eligible Investments	Caps	Special Treatment of Cost Variances	Other Provisions	Case Reference
CA	Southern California Edison	Bundled power service	Palo Verde Incremental Cost Balancing Account	Incremental capital investments in Palo Verde nuclear generating facility	Caps established in settlement	None	Costs up to caps deemed prudent. Company must show that costs in excess of caps are reasonable. If costs exceed caps and generating operating efficiency is low, cost in excess of cap may be disallowed. Decision tied to restructuring of electric utility industry and recovery of sunk costs. Separate incentive mechanism on nuclear operating efficiency continued during term of mechanism.	Decision 96-12-083 (December 1996)
CA	Southern California Edison	Power Distribution	Advanced Metering Infrastructure Balancing Account	Predeployment of AMI	Hard cap for each phase of project	None	Costs up to caps deemed prudent.	Decision 07-07-042 (July 2007)
CA	Southern California Edison	Power Distribution	SmartConnect Balancing Account	Deployment of AMI	Costs up to cap deemed ex ante prudent; Exceptions to cap permitted based on force majeure events, changes in scope of project due to government or regulatory action, and delay in Commission approval.	No deadbands. Asymmetrical Mechanism wherein 90% of first $100 million over the cap charged to ratepayers (No prudence review required)	Costs above cap and incentive mechanism may be recovered in rates following prudence review.	Decision 08-09-039 (September 2008)
CA	Southern California Edison	Power Generation	SONGS 2&3 Steam Generator Replacement Balancing Account	Steam generator replacement project at San Onofre Nuclear Generating Station	Expenditures up to cap deemed prudent. Cap adjusted for actual inflation and changes in the cost of capital.	Deadband of 15% above cap.	Cap can only be exceeded if amount passes subsequent prudence review. If Commission believes costs are unreasonable regardless of amount, it may initate a prudence review.	Decision 05-12-040 (December 2005)
CA	Southern California Gas	Gas	Advanced Metering Infrastructure Balancing Account	AMI	Expenditures up to cap deemed prudent. Cost underspending in each year permitted.	Overrun sharing mechanism: Up to $50 million to be paid by shareholders, calculated as 50% of first $100 million over total cost; Underrun sharing mechanism: Up to $10 million to be received by shareholders, calculated as 10% of first $100 million under total cost.	Costs above cap and incentive mechanism may be recovered in rates following prudence review.	Decision 10-04-027 (April 2010)
IL	Peoples Gas Light & Coke	Gas	Rider Incremental Cost Recovery	Replacement of cast iron and bare steel facilities	Hard cap of 5% of expected base rate revenues established for most service classes.	None	Commission may request prudence review as part of reconciliation filing. Peoples Gas would have the burden of proof. Company entitled to recovery of all prudently incurred costs.	Case 09-0167 (January 2010)

Table 2 (cont'd)

Jurisdiction	Company Name	Services	Name of Mechanism	Eligible Investments	Caps	Special Treatment of Cost Variances	Other Provisions	Case Reference
MA	National Grid (Massachusetts Electric & Nantucket Electric)	Power Distribution	*Net CapEx Adjustment*	All distribution capital investments	Annual hard cap based on 3 year average of capital expenditure and mechanism approved in general rate case. Soft revenue cap of 3% of total revenues from most recent year from the combined effects of the RDM and the tracker.	None	Prudence determination to be made with annual filing. Costs in excess of cap can be reviewed in next rate case.	DPU 09-39
OK	Oklahoma Gas & Electric	Bundled Power Service	Smart Grid Recovery Rider	Systemwide smart grid implementation	Hard cap approved in settlement. Cap includes a 2.5% variance allowance. Tracker settlement approved by Commission included a budgeted revenue requirement for the entire deployment of smart grid.	None	Prudence determination made in the decision approving the mechanism. Recovery over budgeted amount can only occur in a subsequent proceeding if a determination is made that costs were prudently incurred.	Cause PUD 201000029 (July 2010)
OK	Oklahoma Gas & Electric	Bundled Power Service	System Hardening Program Rider	Undergrounding and other circuit hardening capex and aggressive vegetation management	Hard cap	None	Prudence determination implicitly made before rider change is made.	Cause PUD 20080387, Order 567670 (May 2009)
VA	Washington Gas Light	Gas	Steps to Advance Virginia's Energy (SAVE) Rider	Replacement of bare and unprotected steel mains and services and of mechanically coupled pipe	Caps for entire project, subprojects, and calendar years approved in special proceeding authorizing mechanism. Forward-looking budget to be approved in annual proceeding.	Company permitted to exceed total budget cap by 5% overall, has more flexibility with repect to projects and annual spends	Company may request modification of plan limits.	Case PUE-2010-00087 (April 2011)

Table 3

Recent Capex Cost Tracker Precedents with Cost Offsets

State	Company Name	Services	Mechanism Name	Eligible Investments	Case Reference
AR	CenterPoint Energy Arkla	Gas	Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
CA	Pacific Gas & Electric	Gas & Power Distribution	Smart Meter Balancing Accounts	Advanced metering infrastructure ("AMI")	Decision 06-07-027 (July 2006)
CA	San Diego Gas & Electric	Power Distribution	Advanced Metering Infrastructure Balancing Account	AMI	Decision 07-04-043 (April 2007)
CA	Southern California Edison	Power Distribution	SmartConnect Balancing Account	AMI Deployment	Decision 08-09-039 (September 2008)
CA	Southern California Gas	Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 10-04-027 (April 2010)
GA	Atlanta Gas Light	Gas	Strategic Infrastructure Development and Enhancement Program	Replacement of pre-1985 plastic mains and services, planned customer expansions, and infrastructure improvements that sustain reliability and operational flexibility	Dockets 8516-U and 29950 (October 2009 and August 2013)
GA	Atmos Energy (now Liberty Utilities)	Gas	Pipe Replacement Surcharge	Replacement of cast iron and bare steel pipe	Docket 12509-U (December 2000)
IL	Peoples Gas Light & Coke	Gas	Rider Incremental Cost Recovery	Replacement of cast iron and bare steel facilities	Case 09-0167 (January 2010)
KY	Atmos Energy	Gas	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocates	Docket 2009-00354 (May 2010)
KY	Columbia Gas	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 2009-00141 (September 2009)
KY	Union Light, Heat and Power (Duke Energy Kentucky)	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel gas mains and services	Docket 2001-00092 (January 2002)
MA	Bay State Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel mains and services	DPU 09-30
MA	National Grid (Boston-Essex Gas and Colonial Gas)	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators	DPU 10-55
MA	New England Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of non-cathodically protected steel mains and services and small diameter cast and wrought iron	DPU 10-114
NY	Consolidated Edison	Power Distribution	Monthly Adjustment Clause	AMI, supervisory control and data acquisition network, undergrounding	Case 09-E-0310 (October 2010)
OH	Columbia Gas of Ohio	Gas	Infrastructure Replacement Program Rider	AMI, replacement of cast iron and bare steel mains & services	Cases 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case 09-1036-GA-RDR (April 2010)
OH	Duke Energy Ohio	Gas	Accelerated Main Replacement Program Rider	Replacement of cast iron and bare steel mains and services	Case No. 01-1228-GA-AIR, and 01-1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR, 07-0590-GA-ALT, and 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Gas	Advanced Utility Rider	Gas AMI	Cases 07-0589-GA-AIR, 07-0590-GA-ALT, and 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Power Distribution	Infrastructure Modernization Distribution Rider	Electric AMI	Cases 08-920-EL-SSO, 08-921-EL-AAM, 08-922-EL-UNC, and 08-923-EL-ATA (December 2008)

Table 3 (cont'd)

State	Company Name	Services	Mechanism Name	Eligible Investments	Case Reference
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Pipeline Infrastructure Replacement Rider	Pipelines & faulty riser replacements	Case 09-458-GA-RDR (December 2009)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Automated Meter Reading Charge	AMI	Cases 07-0829-GA-AIR, 07-0830-GA-ALT, 07-0831-GA-AAM, 08-0169-GA-ALT, and 06-1453-GA-UNC (October 2008); Case 09-38-GA-UNC (May 2009); Case 09-1875-GA-RDR (May 2010)
OK	Oklahoma Gas & Electric	Bundled Power Service	Smart Grid Recovery Rider	Smart grid	Cause PUD 201000029 (July 2010)
OR	Northwest Natural Gas	Gas	NA	AMI	Docket UM 1413, Order 09-105 (March 2009)
OR	Portland General Electric	Bundled Power Service	NA	AMI	Docket UE 189, Order 08-245 (May 2008)
PA	Metropolitan Edison	Power Distribution	Smart Meter Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Electric	Power Distribution	Smart Meter Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Power Distribution	Smart Meter Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
TX	AEP Texas Central	Power Distribution	Advanced Metering System Surcharge	AMI	Docket 36928
TX	AEP Texas North	Power Distribution	Advanced Metering System Surcharge	AMI	Docket 36928
TX	Oncor Electric Delivery	Power Distribution	Advanced Metering System Surcharge	AMI	Docket 35718 (August 2008)
TX	Texas-New Mexico Power	Power Distribution	Advanced Metering System Surcharge	AMI	Docket 38306

Diego Gas & Electric's AMI tracker. San Diego Gas & Electric's AMI tracker also authorized a sharing of the first $50 million under the budget, with 10% going to the company. Southern California Gas' AMI tracker was similar to San Diego Gas & Electric's. However, the Southern California Gas AMI tracker lacked a *force majeure* provision and had a larger amount at risk. The company could recover 50% of the first $100 million above the budget and 10% of the first $100 million under the budget without a further prudence review.

Recommendations

If the Commission permits continuation of capital cost trackers in next generation PBR, the following is a "short list" of reforms that merit consideration.

Incentivization Provisions The Commission discussed the option of incentivizing capital trackers in the Final Issues List.[45] We discussed above several established ways to incentivize capital cost trackers, and all of these merit consideration.

- Variances between forecasted and actual tracked capital costs can be shared automatically between utilities and customers in certain ranges.
- A deadband can be established in which variances do not trigger revenue adjustments. If capex exceeds the forecasted amount, for example, the utility may have to absorb the first $3 million dollars of overspend and can keep the first $3 million of underspend.
- Recovery of cost overruns outside of these ranges can be delayed for consideration in the next rate case, with no compensation for the extra costs that are incurred in the interim.
- A hard cap can be placed on tracked costs.

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[45] AUC Final Issues List, *op. cit.,* p. 12.

A utility's reward for an in-service date for a project that is later than forecasted should not exceed a reasonable share of the (typically modest) value to customers of deferring projects.

There are pros and cons to increased tracker incentivization.

<u>Pro</u>

- Capex containment incentives are strengthened by such provisions.
- The incremental administrative cost of such provisions is small.

<u>Con</u>

- Increased incentivization increases the incentive of utilities to exaggerate their capex needs. The incentive utilities have to exaggerate future cost growth in proceedings to design PBR plans has driven regulators in other jurisdictions to rely extensively on independent engineering and benchmarking studies to appraise the need for capex. In British PBR plans, for example, utility revenue requirements are chiefly based on the regulator's own cost forecast.

On balance, we believe that increased capital tracker incentivization by some combination of these means is desirable.

Overcompensation Provisions We noted above that there is a serious concern with overcompensation in the current plan. Here are some ways to address the problem. We discuss pros and cons of each.

1. Separate Indexing of O&M and Capital Revenue

In the Final Issues List, the Commission mentions the option of "excluding all capital from the going in rates and the I-X mechanism (a hybrid PBR plan that focusses on operations and maintenance expenses only)". We do not recommend this approach due to its high incremental administrative cost, the weak, imbalanced incentives for capex containment it would generate, and the unusually small importance of distributor O&M expenses in Alberta.

However, this idea opens the door to having separate index-based escalators for O&M expenses and capital in power distributor regulation. The X factor for O&M revenue (which might be denoted "XOM") could be based on the higher O&M productivity trend of the peer group. The X factor for capital revenue (which might be denoted "XK") would reflect the (slower) capital productivity growth trend. XK would be used in the accounting test formula.

<u>Pro</u>

- Overcompensation is reduced, since the I-X revenue in the accounting test is higher.
- Incentives to contain O&M expenses are not weakened by a higher X factor for O&M revenue.
- The incremental administrative cost of separate indexation is low.
- There is precedent for separate indexation of O&M and capital cost in the PBR plans of the Fortis companies in BC. The Fortis plans are discussed further in Appendix Section A.2.1.

<u>Con</u>

- Controversy over productivity trends in PBR proceedings like this one would be broadened to include partial factor productivity.
- This reform does not address *intertemporal* overcompensation since distributors are compensated for periods of slow capital productivity growth while the periods of rapid productivity growth that will be needed in the future to attain the MFP trend of the peer group are ignored.
- Incentives to contain capex aren't strengthened.

2. Remove the Stretch Factor from the Accounting Test Formula

The stretch factor can be removed from the I-X formula used in the accounting test. This is done by the Ontario Energy Board when reviewing cost forecasts in custom IR applications. Ratemaking treatment of capital in Ontario PBR is discussed further in Appendix Section A.2.2.

Pro

- Overcompensation will be reduced because the accounting test will indicate smaller revenue shortfalls.
- The incentive to contain capex will be slightly strengthened.
- The incremental administrative cost of excluding the stretch factor from the formula is trivial.

Con

- Utilities will argue that their capital cost projections implicitly reflect efficient cost.

3. Historical Review Window

The Commission mentions in the final issues list the option of "eliminating the *forecast* component of capital trackers, requiring the companies to make capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker."[46] This is presented as a way of incentivizing the tracker but can also mitigate the overcompensation problem.

[46] AUC Finals Issues List, *op. cit*., p. 12

Pro

- o Overcompensation is reduced and capex containment incentives are strengthened slightly by trimming tracker revenue. Utilities also confront greater prudence risk.
- o Since the resultant reduction in tracker revenue is modest, it Is unlikely to be excessive.
- o The incremental administrative cost is low, since backward-looking tracker administration proceedings are not self-evidently more time consuming.
- o Historical test years are used in rate cases in many U.S. jurisdictions.

Con

- o There is some merit to having the Commission review in advance the need for tracker surges.

4. Ignore a Share of the Initial Revenue Shortfall

Alternatively, the utility can be denied a share of the temporary revenue shortfall that is forecasted using the accounting test. This was also mentioned by the Commission in its final issues list (p.12).

Pro

- o Overcompensation is reduced. Capex containment incentives are strengthened.
- o The incremental administrative cost is low.

Con

- o The extent of future revenue surpluses is unclear since the future of ratemaking is unclear. For example, PBR might not continue for fifty years. Thus, the appropriate amount of the initial revenue shortfall to ignore is unclear. This is, in other words, a blunt tool for addressing overcompensation.

5. Tighten Eligibility Criteria

Eligibility criteria can be tightened.[47] For example, the Commission can raise the materiality thresholds and/or exempt growth-related capex from eligibility. Materiality thresholds are higher in both Ontario and British Columbia.

Pro

- Overcompensation is reduced. Capex containment incentives are strengthened.
- Regulatory cost is reduced by narrowing the scope of cost events eligible for tracking.

Con

- The extent of future revenue surpluses is unclear since the future of ratemaking is unclear. Thus, the appropriate amount of the initial revenue shortfall to ignore is unclear.

6. Ongoing Tracking of Eligible Costs

Costs tracked in one proceeding can continue to be tracked following the expiration of a plan, thereby assuring customers the benefit of the subsequent depreciation.

Pro

- Overcompensation is reduced.

[47] In U.S. regulation, it is not unusual for a commission to consciously undercompensate a utility in one area, confident in the knowledge that there may be overcompensation in other areas and that the undercompensation strengthens incentives. A good example is the widespread use of historical test years.

- Capex containment incentives are strengthened, since the benefit to utilities of higher revenue now is reduced by cost of higher X factors.
- There are no worries about future rate regulation uncertainty.

<u>Con</u>

- There is modest incremental regulatory cost to continue tracking tracked capital cost after a plan expires. The Commission has deemed this approach too complicated, but the PBR plans for the two Fortis companies in BC routinely track the cost of *all* older capital.
- The utility is still guaranteed recovery of the part of capex deemed prudent.
- The freedom of future regulators is abridged.

7. Raise Future X Factors

The utility can be obliged to raise future X factors the more supplemental revenue it asks for to fund conventional capex in order to ensure that customers get the benefit of peer group productivity growth in the long run. For example, if the utility asks for 1% supplemental revenue escalation in year t, X can be raised by 1/50 = 0.02% in year t and the subsequent 49 years of PBR. Utilities may request exemption from this requirement on the grounds that the required capex materially exceeds that funded by the long-term productivity trend of the peer group. However, the burden of proof is on them to demonstrate the contention.

<u>Pro</u>

- Overcompensation is reduced.
- Capex containment incentives are strengthened. The utility must grapple with the need to achieve long-run MFP growth equal to that of the peer group.
- Customers receive the benefit of long-run MFP growth of the peer group.

- There are fewer worries about future rate regulation uncertainty.

Con

- There is modest incremental regulatory cost.
- X factors are raised so long as index-based PBR continues. Hence, X factors may rise to levels that utilities claim are unsustainable.[48]
- The freedom of future regulators is abridged.

We believe that this option merits short list consideration.

8. Recalculate MFP to Correspond to the Costs to which X Applies

The MFP trend of the peer group can be adjusted to reflect the fact that the utility is left whole for events that accelerate capital cost. For example, the MFP trend can be adjusted to reflect the fact that a certain percentage of capex is tracked.

Pro

- Overcompensation is reduced.

Con

- The incentive to contain tracked capex isn't strengthened.
- X factor adjustments could be complex and controversial. For example, it would be difficult to know what share of capex would be tracked.

9. Net Expected O&M Cost Savings from Eligible Capital Cost

Pro

- Overcompensation is reduced.

[48] Such claims are tantamount to saying that they cannot achieve the long-run MFP trend of the peer group.

- This procedure is commonplace in Ontario and U.S. capital cost trackers when material O&M cost savings are expected from capex.

Con

- Expected O&M cost savings can be difficult to estimate accurately. Controversy may ensue.
- The incremental administrative cost of a tracker application proceeding can be considerably higher.

10. Strengthen Prudence Reviews of Tracked Capex

The AUC can, in principle, strengthen its ability to make independent judgements on capex needs.

Pro

- Capex containment incentives are strengthened.

Con

- Greater attention to the prudence of utility capex can materially raise regulatory cost.
- Asymmetry of information favors utilities in prudence reviews.

It is interesting to note that some ways of reducing double counting also strengthen capex containment incentives and, by reducing the incentive to lodge requests, can also reduce regulatory cost. Furthermore, none of these approaches carries the risk of clawback of cost performance gains achieved under the stimulus of PBR.

11. Adjust X to Reflect Opportunities for Scale Economies

Since capital trackers provide supplemental revenue for rapid capital cost growth from various causes, plan terms can be adjusted to take more account of the cost impact of *favorable* operating conditions in Alberta. For example, X factors can be based on a productivity peer group that experienced brisk demand growth like the Alberta distributors are expecting.[49] The X factor could also be raised by removing utilities from the sample that were hit by hurricanes.

Pro

- Overcompensation is reduced.
- There is no incremental administrative cost to adjusting X since it is going to be adjusted anyways.
- Cost containment incentives are not weakened by a higher X.
- Utilities have advocated X factors based on custom peer groups in many North American PBR proceedings.

Con

- Controversy over productivity trends in PBR proceedings like this one will be broadened to include consideration of scale economies.
- Incentives to contain tracked capex are not strengthened.

An alternative to raising X is to use the estimated revenue reductions from a higher X to offset supplemental revenue in tracker applications.

[49] Peer groups can in principle be chosen to reflect other favorable productivity drivers as well.

4. X Factor

4.1 Basic Indexing Concepts

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

Input Price and Quantity Indexes

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

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

These indexes summarize trends in the input prices and quantities that make up the cost. A cost-weighted input *price* index measures the impact of price inflation on the cost of a bundle of inputs. A cost-weighted input *quantity* index measures the impact of quantity growth on cost. Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by gas and electric power distributors. These are capital intensive businesses, so the heaviest weights are placed on the capital subindexes.

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

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

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

Productivity Indexes

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

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

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

$$trend\ Productivity = trend\ Outputs - trend\ Inputs. \qquad [4]$$

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

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. A *multifactor* productivity ("MFP") index measures productivity in the use of multiple inputs. Some indexes measure productivity in the use of a single input class such as labor. These indexes are sometimes called partial factor productivity ("PFP") indexes.

Output Indexes The output (quantity) index of a firm or industry summarizes trends in the scale of its operation. Growth in each output dimension that is itemized is measured by a subindex. In designing an output index, choices concerning subindexes and weights should depend on the manner in which the index is to be used.

One possible objective is to measure the impact of output growth on *revenue*. In that event, the subindexes should measure trends in *billing determinants* such as the delivery volume and peak demand. The weight for each itemized determinant should be its share of revenue.[50] In this report we denote by $Outputs^R$ an output index that is revenue-based in the sense that it is designed to measure the impact of output on revenue. A productivity index that is calculated using $Outputs^R$ will be denoted as $Productivity^R$.

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

Another possible objective of output research is to measure the impact of output growth on company *cost.* In that event it can be shown that the subindexes should measure the dimensions of the "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers. The sensitivity of cost to the change in a business condition variable is commonly measured by its cost "elasticity." Elasticities can be estimated econometrically using data on the operations of a group of utilities. A multiple category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver. A productivity index calculated using a cost-based output index will be denoted as $Productivity^C$.

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

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth Research by economists has found the sources of productivity growth to be diverse.[51] One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are another important source of productivity growth. These economies are available in the longer run if cost has a tendency to grow less rapidly than

[50] This approach to output quantity indexation is credited to the French economist Francois Divisia.

[51] A classic paper by Denny, Fuss, and Waverman provides a mathematical analysis of this topic.

output. A company's potential to achieve incremental scale economies depends on the pace of its workload growth. Incremental scale economies (and thus productivity growth) will typically be reduced the slower is output growth.

A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth will increase (decrease) to the extent that X inefficiency diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current efficiency level.

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

An MFP index with a *revenue*-weighted output index has an important driver that doesn't affect a *cost efficiency* index. To understand why, consider that

$$
\begin{aligned}
\textit{growth } MFP^R &= \textit{growth Outputs}^R - \textit{growth Inputs} + \\
&\qquad (\textit{growth Outputs}^C - \textit{growth Outputs}^C) \\
&= (\textit{growth Outputs}^C - \textit{growth Inputs}) + (\textit{growth Outputs}^R - \textit{growth Outputs}^C) \\
&= \textit{growth } MFP^C + (\textit{growth Outputs}^R - \textit{growth Outputs}^C)
\end{aligned}
$$

The growth in MFP^R can be decomposed into the growth in a cost efficiency index and an "output differential" that measures the difference between the impact that demand growth has on revenue and cost.

To understand why the output differential matters, consider that

$$\textit{growth Revenue/Cost} = \textit{growth Revenue} - \textit{growth Cost}$$

$$= (\textit{growth Output Prices}^R + \textit{growth Outputs}^R) - (\textit{growth Input Prices} - \textit{growth MFP}^C + \textit{growth Outputs}^C)$$

$$= \textit{growth Output Prices} - \textit{growth Input Prices} + [(\textit{growth MFP}^C + (\textit{growth Outputs}^R - \textit{growth Outputs}^C)]$$

Utility earnings are bolstered by a positive output differential. The output differential can be positive, accelerating growth in MFP^R, when billing determinants grow more rapidly than the demand drivers that affect cost.

Rate designs and the size of conservation and demand management ("CDM") programs in a utility's service territory are important drivers of its output differential. When residential volumetric charges are high, for example, volume growth may have more impact on revenue than on cost, bolstering earnings and reducing the need for higher rates. Volume growth often drives growth in the revenue of residential and small business customers, whereas we have noted that customer growth is highly correlated with aspects of demand that drive cost growth. The earnings growth of many energy distributors is thus especially sensitive to the trend in residential and commercial volume per customer (aka average use).

4.2 Use of Index Research in Regulation

Price Cap Indexes

Early work to use indexing in ARM design focused chiefly on *price* cap indexes ("PCIs"). We begin our explanation of the supportive index logic by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[52] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

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

$$trend\ Revenue = trend\ Cost. \qquad [6]$$

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

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

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

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

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

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

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

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

Since the X factor often includes a stretch factor, it is sometimes said that the index research on productivity trends has the goal of "calibrating" (rather than solely determining) X.

Revenue Cap Indexes

General Result Index research also provides the basis for revenue cap indexes. Several approaches to the design of revenue cap indexes are consistent with index logic. One approach is grounded in the following basic result of cost research:

$$\textit{trend Cost} = \textit{trend Input Prices} - \textit{trend Productivity}^C + \textit{trend Outputs}^C. \qquad [10a]$$

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

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

where

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

Productivity research to calibrate X should use an output index that features important cost drivers.

Application to Energy Distributors For gas and electric power distributors, the number of customers served is a useful scale variable to use in revenue cap index design. It is an important cost driver in its own right and also highly correlated with other cost drivers such as peak load.[53] For an energy distributor, $Outputs^C$ can thus be reasonably approximated by growth in the number of customers served and there is no need for the complication of a multidimensional output index with cost elasticity weights. Relation [10a] can then be restated as

$$\begin{aligned}
&\textit{trend Cost} \\
&\quad = \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\
&\quad = \textit{trend Input Prices} - \textit{trend } MFP^N + \textit{trend Customers} \qquad [11a]
\end{aligned}$$

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

[53] This is so because the total number of customers is dominated by the number of residential and small commercial customers, and these customers tend to have more peaked loads.

Rearranging the terms of [11a] we obtain

$$\textit{trend Cost} - \textit{trend Customers}$$

$$= \textit{trend}\ (\textit{Cost/Customer}) = \textit{trend Input Prices} - \textit{trend } MFP^{N}. \qquad [11b]$$

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

$$\textit{growth Revenue/Customer} = \textit{growth Input Prices} - X + Y + Z \qquad [11c]$$

where

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

This general formula for the design of revenue cap indexes is currently used in the PBR plans of AltaGas, ATCO Gas, and Gazifère in Canada. The Régie de l'Energie in Québec has directed Gaz Métro to develop a PBR plan featuring revenue per customer indexes. Revenue per customer indexes were previously used by Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the U.S. and Canada, respectively.

Application to O&M Expenses Index logic also provides general formulas for escalating utility revenue that addresses subsets of the total cost of base rate inputs, such as capital and O&M expenses. For each cost category j the general formula is

$$\textit{trend Cost}_j = \textit{trend Input Prices}_j - \textit{trend } PFP_j^{\,C} + \textit{trend Outputs}_j^{C}. \qquad [12a]$$

Here PFP is an index of productivity in the use of class j inputs. Formula [12a] provides the basis for the following O&M escalator:

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

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

Here $PFP_{O\&M}^{C}$ is an O&M productivity growth target. O&M revenue escalation formulas like [12b] are an example of "productivity-based budgeting" and have been used by regulators in Australia to establish multiyear O&M budgets for energy distributors in PBR plans.

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

4.3 Index Methods for X Factor Calibration

Capital Cost

Trends in the price and quantity of capital play a critical role in the measurement of trends in multifactor productivity and the prices of base rate inputs due to the typically high share of capital in total cost. The capital cost share is especially high in a study to calibrate X factors for Alberta distributors because the utilities do not have sizable customer-related O&M expenses. A practical means must be found to calculate capital cost and to decompose it into consistent price and quantity indexes such that

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

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

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

- The geometric decay ("GD") method assumes a current valuation of capital and a constant rate of depreciation. These assumptions produce capital service price and quantity indexes that are mathematically simple and easy to code and review. This method has been widely used in productivity research. Although the assumptions underlying the GD method are very different from those used to compute capital cost in utility regulation, the GD method has been used on many occasions in research intended to calibrate utility X factors.

- The one hoss shay approach to capital costing assumes that plant does not depreciate gradually but, rather, all at once as the asset reaches the end of its service life. The plant is valued in current dollars. Although the assumptions underlying the one hoss shay method are very different from those used to compute capital cost in utility regulation, the method has been used occasionally in research intended to calibrate utility X factors. Examples include the two studies prepared by NERA for Alberta PBR proceedings.
- The cost of service ("COS") approach to calculating capital cost, prices, and quantities is designed to approximate the way capital cost is calculated in utility regulation. This approach is based on the assumption of straight line depreciation and the historic (book) valuation of capital. PEG Research personnel have used this approach in a number of X factor calibration studies, including our 2012 study for the CCA.

Utilities have diverse methods for calculating depreciation and the depreciation treatments of individual utilities change over time. In calculating capital costs and quantities, it is therefore generally considered desirable to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment. Since the quantity of capital on hand may involve plant added thirty to fifty years ago, it is desirable to have gross plant addition data for many years in the past.

For older periods in which plant addition data are unavailable, it is customary to consider the net plant value near the end of this period and then estimate the quantity of capital it reflects using construction price indexes from earlier years and assumptions about the past pattern of investment. The year in which this exercise takes place is commonly called the "benchmark year." Since this exercise is unlikely to be exact, it is advisable to base X factor research on a sample period that begins many years after the benchmark year.

Choosing a Base Productivity Growth Target

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

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion in Section 4.1 of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause different utilities to have different productivity trends. For example, energy distributors experiencing brisk growth in the number of customers served are more likely to realize economies of scale that accelerate productivity growth than distributors experiencing average customer growth.

There is thus considerable interest in methods for customizing base productivity growth targets to reflect local business conditions. The most common approach to customization in PBR proceedings has been to use the average productivity trends of *similarly situated* utilities. Relevant conditions for a power distributor include the growth in the number of electric and natural gas customers served.

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

Data on the operations of U.S. utilities are well-suited for the requisite price and productivity research. Standardized data of good quality have been available from government agencies on utility operations for many years. For electric utilities, the primary source of these data is the Federal Energy Regulatory Commission ("FERC") Form 1, which provides detailed cost data and some useful data on operating scale. Major investor-owned electric utilities in the United States are required by law to file this form annually. Cost and quantity data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

These data have been available for decades, providing the basis for more accurate capital quantity indexes. We have noted that the accuracy of these indexes is very important in studies of distribution productivity. The large size of the U.S. and the balkanized character of service territories means that data are available for a large number of utilities operating under diverse conditions. This facilitates development of custom productivity peer groups.

Custom productivity peer groups have frequently been used in X factor calibration research, and that practice has by no means been confined to regulatory commissions and consumer advocates. In New England, for example, utilities have proposed and regulators have approved X factors in index-based PBR plans that are calibrated using research on the productivity trends of Northeast utilities. Custom peer groups have been used by the Brattle Group and Concentric Energy Advisors in X factor calibration research for Enbridge Gas Distribution.

Unfortunately, the number of utilities, for which good data are available, which face productivity growth drivers similar to those facing the subject utility is sometimes limited. This is a chronic problem in Canada, where standardized data that could be used to accurately measure the productivity trends of appropriate peer groups are not readily available.

Standardized operating data have recently become available for the numerous Ontario power distributors. PEG Research has used these data to estimate industry productivity trends in X factor calibration work commissioned by the Ontario Energy Board. These data have a number of limitations in productivity research that limit their usefulness in Alberta PBR.

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

Due to the limitations of Canadian data, regulators in Alberta and British Columbia have based X factors in their MRPs for gas and electric power distributors on the productivity trends of U.S. distributors. The Ontario Energy Board used estimates of U.S. productivity trends to choose the productivity target in its third generation plan for power distributors. Union Gas agreed to a settlement that reflected X factor calibration research based on U.S. data.

The complications of basing X on the productivity trends of other utilities have occasionally prompted regulators to base X factors on a utility's *own* recent historical productivity trend. This approach will weaken a utility's incentives to increase productivity growth if used repeatedly. Furthermore, a utility's productivity growth in one five or ten year period may be very different from its productivity growth potential in the following five years. For example, a ten-year period in which productivity growth was slowed by high capex may be followed by a period of brisk productivity growth.

A special complication in choosing a productivity peer group for a *price* cap X factor for Alberta utilities is that the candidate peers can have different output differentials even if they have similar cost efficiency trends. Many American service territories, for example, nowadays have large conservation and demand management programs that materially slow volume growth.

To finesse this problem, we recommend calibrating the X factors for price cap plans of Alberta power distributors using the same *cost efficiency* indexes (i.e., with customers as the output measure) that we are using to calibrate X for the gas distributor revenue caps. An adjustment to X can be added if needed for the output differentials of Alberta utilities. We may adjust our recommended X factors for Alberta power distributors in our rebuttal testimony to reflect output differentials depending on data gathered from these companies in information requests. The issue of output differentials can be sidestepped by using *revenue* cap indexes in next generation PBR plans for power distributors.

<u>Data Quality</u>

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

4.4 Need for New Productivity Research

We believe that X factors in next generation Alberta PBR plans should continue to be the sum of productivity growth targets and a stretch factor. Distributor cost growth is typically gradual so that I-X mechanisms can be developed that give distributors a reasonable chance to recover their efficient cost of service. There can be less reliance on cost forecasts in ratemaking. Customers can be guaranteed the benefit of productivity growth that is superior to the industry norm. This approach to energy utility regulation is currently used in British Columbia and Ontario as well as Alberta and may expand soon in Québec. Québec is seriously considering its use in power transmission regulation as well as distribution.

Power Distributors

There is a need for a new independent power distributor productivity study, for several reasons.

- One or more of the power distributors may file a study in this proceeding. Such submissions could be controversial and increase the need for an independent study.
- Dr. Makholm's productivity research is now out of date. The last year of his sample period was 2009, and data are now available to 2014.
- There are no approved estimates in Alberta of the productivity trends of O&M and capital inputs.
- PEG challenged many aspects of the NERA productivity methodology in its CCA testimony in ID 566.[54]
    - The chosen multilateral form of the index is not optimal for measuring productivity *trends*. This compromises the accuracy of results in the later years of the sample period.
    - There was an uncorrected error in the benchmark year adjustments for all sampled utilities. This resulted in depreciation of benchmark year capital being removed from the calculations; thereby slowing estimated MFP growth.
    - The volumetric output index produces results of limited relevance in an Alberta application. Gas distributors operate under revenue-per-customer indexes, and some power distributors have high customer charges.

[54] Lowry, M., Hovde, D., and Kalfayan, J., *PBR Plans for Alberta Energy Distributors,* AUC Proceeding 566, Exhibit 0307.01.CCA-566, December 2011.

- The methodology produced a *positive long-run* MFP trend but a materially *negative* trend for the later years of the sample period. This invites "cherry picking" by utility witnesses of a recent sample period as the basis for X.
- There was no attempt to customize results for special operating conditions in Alberta. These conditions include relatively brisk demand growth which tends to accelerate productivity growth due to increased opportunities to realize scale economies.
- NERA did not consider Alberta input price trends, and their "one-hoss shay" treatment of capital cost is quite different from the treatment under Alberta regulatory cost accounting and hence ill-suited for evaluating such trends.

We believe that the base productivity trend chosen by the Commission was nonetheless reasonable. However, it would be wise not unwise to limit the empirical evidence in this proceeding to an update of the NERA study.[55] The Commission should have the option of basing next-generation X factors on a study that uses alternative methods and is more customized to special operating conditions in Alberta.

- Thought should also be paid to commencing work on the productivity trends of Alberta utilities as a point of comparison. It is desirable to know whether recent high earnings reflect real performance improvements.

Here are some pros and cons to undertaking an analogous study of the productivity of U.S. *gas* distributors.

[55] The numerous deficiencies of NERA's methodology call into question why any other witness in this proceeding would choose to use it for an X factor recommendation.

Pro

- Alberta distributors may commission their own gas productivity study or assert the need to make adjustments to productivity results for U.S. power distributors. Such submissions could also be controversial and increase the need for an independent study.
- Previous work by PEG Research indicated that the O&M and capital productivity trends of U.S. gas distributors are dissimilar to those for U.S. power distributors.

Con

- The multifactor productivity trend of gas distributors is likely to be fairly similar to that for power distributors.
- The Commission elected last time to base the X factors for gas distributors on the MFP trend of power distributors. If it was content to do so then it may be content to do so now.
- The required gas data are considerably more difficult to obtain. The most economical approach to obtaining these data is to lease them from a reputable vendor such as Ventyx (price tag: about $USD 30,000). However, parties to this proceeding would then be required to sign a confidentiality agreement strictly limiting their use of these data to this proceeding.[56] The AUC objected to such an arrangement in the last generic proceeding.

Based on this analysis, the CCA has elected to commission for direct testimony only a study of power distribution productivity. The need for a gas distribution study will be reconsidered when the testimony of other witnesses becomes available.

[56] This has never posed a problem in other jurisdictions.

4.5. New Results on Productivity Trends of U.S. Power Distributors

Data

The primary source of the cost and quantity data used in our power distribution index research for the CCA in this proceeding was the FERC Form 1. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[57] More recently, the data have been available electronically in raw form from the FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained directly from the FERC and processed by PEG Research.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the United States that filed the Form 1 electronically in 2014 and that, together with any important predecessor companies, have reported the necessary data continuously since they achieved a "major" designation. To be included in the study the data were required, additionally, to be of good quality and plausible. One important quality criteria was that there were no accounting-related changes in the definition of distribution plant. Data from 88 utilities met these standards and were used in our indexing work. We believe that the data for these companies are the best available for rigorous work on input price and productivity trends to support the development of X factors for Alberta power distributors.

The included companies are listed in Table 4. It can be seen that all broad regions of the United States are well-represented. Unfortunately, all requisite data are not available for Texas distributors.

A noteworthy idiosyncrasy of the FERC Form 1 is that it requests data on retail power *sales* volumes but not on the volumes of *unbundled distribution* services that might be provided

[57] This publication series had several titles over the years. A recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*

Table 4

Companies in the Total Factor Productivity Sample

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

Notes:
Italicized companies are in the rapid growth peer group.
An * denotes that a company is in the Mountain West peer group.

under retail competition. Where retail competition exists, this complicates accurate calculation of trends in the number of retail customers as well. To rectify this shortcoming, we relied primarily on Form EIA-861, the *Annual Electric Power Industry Report*, for our customer data in the years for which this distinction is important.

Other sources of data were also accessed in the research. These were used primarily to measure input price trends. The supplemental data sources were Whitman, Requardt & Associates and the U.S. Bureau of Labor Statistics. The specific data drawn from these and the other sources mentioned are discussed further below.

Index Details

Scope We calculated indexes of trends in the O&M, capital, and multifactor productivity of each sampled utility in the provision of power distribution services. Arithmetic averages of those trends were then calculated for all sampled companies and some subsets that merit consideration as productivity peer groups.

The major tasks in a power distribution operation are the local delivery of power, the reduction of its voltage, and the metering of quantities delivered.[58] U.S. distributors also typically provide an array of customer services such as account, sales, and information services.

The total cost of power distribution considered in the study was the sum of applicable O&M expenses and capital costs. Reported costs of any gas services provided by combined gas and electric utilities in the sample were excluded.[59] We also excluded certain itemized costs that are unlikely to be subject to indexing in next-generation PBR for Alberta utilities. The costs excluded for this reason were expenses for purchased power, power transmission by others, franchise fees, customer service and information, sales, and most customer account functions.

[58] Most power is delivered to end users at the voltage at which it is consumed.

[59] Gas service costs of combined gas and electric utilities are itemized on FERC Form 1, facilitating their removal.

Capital cost is the sum of depreciation expenses, a return on the value of net plant, and taxes. The featured results were produced using a geometric decay approach to the measurement of capital cost. Similar results were achieved using the cost of service approach to capital costing.

Applicable O&M expenses included those reported for power distribution and meter reading, plus a sensible share of the company's administrative and general ("A&G") expenses (exclusive of those for pensions and benefits) and general plant costs. A&G expenses are O&M expenses that are not readily assigned directly to particular operating functions under the Uniform System of Accounts. They include expenses incurred for injuries and damages, property insurance, regulatory proceedings, stockholder relations, and general advertising of the utility; the salaries and wages of A&G employees, and expenses for office supplies, rental services, outside services, and maintenance activities that are needed for general administration.

General plant is plant that is not directly assigned to particular operating functions in the Uniform System of Accounts. Certain structures and improvements (e.g., office buildings), communications equipment, office furniture and equipment, and transportation equipment account for the bulk of general plant value. Other general plant categories in the Uniform System of Accounts include tools, shop, and garage equipment, laboratory equipment, miscellaneous power-operated equipment, land and land rights, and stores equipment.

Index Construction

Productivity growth was calculated for each sampled utility as the difference between the growth rates of output and input quantity indexes. The growth of each output quantity index is the growth in the total number of retail customers served. The resultant productivity indexes are cost efficiency indexes. Depending on the responses to data requests, we may propose adjustments to results using these indexes for output differentials in applications to power distributors.

In calculating input quantity trends, we broke down the applicable cost into those for distribution plant, general plant, labor, and material and service ("M&S") inputs. The cost of labor was defined for this purpose as O&M salaries and wages and pensions and other benefits. The cost of M&S inputs was defined as applicable O&M expenses net of these labor costs. The calculation of capital cost is discussed further in Appendix Section 3.

The growth of the multifactor input quantity index is a weighted average of the growth in quantity subindexes for labor, materials and services, power distribution plant, and general plant. The growth in the O&M input quantity index used to measure O&M productivity is a weighted average of the growth of the labor and M&S quantity subindexes. The growth of the capital quantity index used to measure capital productivity is a weighted average of the growth of the distribution and general plant quantity subindexes.

The resultant productivity indexes are cost efficiency indexes as discussed in Sections 4.1 and 4.3. We currently lack the information needed for output differential adjustments such as those discussed in Section 4.1. We may propose such adjustments in our rebuttal testimony if suitable data from power distributors can be obtained through information requests.

The Sample

The full sample period was 1997-2014.[60] The start date was the first for which key price data were available. The 2014 end date is the latest for which all data we use to calculate the productivity indexes are as yet available. Data for 2015 will not become available until May of this year.

Index Results

Tables 5a and 5b present key results of our productivity research for the full sample. Inspecting Table 5a it can be seen that, over the full 1997-2014 sample period, the annual

[60] That is to say that the earliest year for growth rate calculations was 1997.

Table 5a U.S. Power Distribution Productivity Trends: Full Sample[61]

Year	Output	Input	Productivity		
			O&M	Capital	MFP
	[A]	[B]			[C=A-B]
1997	1.44%	-0.13%	3.84%	0.62%	1.56%
1998	1.56%	2.71%	-5.64%	0.60%	-1.15%
1999	0.83%	0.03%	1.54%	0.48%	0.80%
2000	1.55%	0.58%	1.77%	0.63%	0.97%
2001	1.79%	0.80%	1.11%	1.30%	0.99%
2002	1.28%	-0.42%	4.52%	0.72%	1.70%
2003	0.75%	2.19%	-5.29%	0.09%	-1.43%
2004	1.11%	-0.29%	3.65%	0.44%	1.40%
2005	1.27%	0.08%	2.62%	0.48%	1.19%
2006	0.50%	0.51%	-0.03%	0.01%	-0.01%
2007	1.06%	1.05%	-0.16%	0.28%	0.01%
2008	0.56%	0.81%	-0.43%	0.16%	-0.25%
2009	0.25%	-0.59%	3.26%	-0.15%	0.84%
2010	0.41%	0.00%	0.29%	0.24%	0.41%
2011	0.29%	-0.22%	0.73%	0.29%	0.51%
2012	0.57%	-0.59%	2.24%	0.74%	1.16%
2013	0.30%	0.31%	1.11%	-0.34%	-0.01%
2014	0.65%	0.75%	-1.52%	0.50%	-0.10%
Average Annual Growth Rates					
1997-2014	**0.90%**	**0.42%**	**0.76%**	**0.39%**	**0.48%**
1997-2007	**1.19%**	**0.65%**	**0.72%**	**0.51%**	**0.55%**
2008-2014	**0.43%**	**0.07%**	**0.81%**	**0.21%**	**0.36%**

[61] Annual growth rates are calculated logarithmically.

Table 5b U.S. Power Distribution Productivity Trends: 10% of Capex Excluded[62]

Year	Output	Input	Productivity		
			O&M	**Capital**	**MFP**
	[A]	[B]			[C=A-B]
1997	1.44%	-0.52%	3.84%	1.16%	1.96%
1998	1.56%	2.35%	-5.64%	1.10%	-0.79%
1999	0.83%	-0.29%	1.54%	0.91%	1.12%
2000	1.55%	0.25%	1.77%	1.07%	1.29%
2001	1.79%	0.49%	1.11%	1.39%	1.30%
2002	1.28%	-0.73%	4.52%	0.88%	2.01%
2003	0.75%	1.95%	-5.29%	0.47%	-1.20%
2004	1.11%	-0.55%	3.65%	0.80%	1.67%
2005	1.27%	-0.17%	2.62%	0.83%	1.44%
2006	0.50%	0.31%	-0.03%	0.33%	0.19%
2007	1.06%	0.87%	-0.16%	0.60%	0.19%
2008	0.56%	0.67%	-0.43%	0.44%	-0.11%
2009	0.25%	-0.75%	3.26%	0.13%	1.00%
2010	0.41%	-0.16%	0.29%	0.65%	0.57%
2011	0.29%	-0.36%	0.73%	0.83%	0.64%
2012	0.57%	-0.75%	2.24%	0.95%	1.31%
2013	0.30%	0.14%	1.11%	-0.10%	0.16%
2014	0.65%	0.63%	-1.52%	0.70%	0.02%
Average Annual Growth Rates					
1997-2014	**0.90%**	**0.19%**	**0.76%**	**0.73%**	**0.71%**
1997-2007	**1.19%**	**0.36%**	**0.72%**	**0.87%**	**0.83%**
2008-2014	**0.43%**	**-0.08%**	**0.81%**	**0.52%**	**0.51%**

[62] Annual growth rates are calculated logarithmically.

average growth rate in the MFP of all sampled U.S. power distributors was about **0.48**%. Output quantity growth averaged **0.90%** annually.[63] Multifactor input quantity growth was slow, averaging **0.42%** annually. O&M productivity growth averaged **0.76%** annually whereas capital productivity growth averaged **0.39%** annually. Note that O&M productivity growth was much more volatile than capital productivity growth from year to year.

Over the more recent 2008-2014 period, the MFP growth of the full sample was a little slower, averaging **0.36%** annually. Thus, there was not a material slowdown in the multifactor cost efficiency trend. O&M productivity growth accelerated slightly to a **0.81%** annual average whereas capital productivity growth slowed to a **0.21%** average.

Table 5b presents productivity results when 10% of plant additions have been removed from the full sample for the 1997-2014 period. It can be seen that the sampled distributors averaged **0.71%** annual MFP growth. O&M productivity growth once again averaged **0.76%** annually but capital productivity growth accelerated, averaging **0.73**% annually.

We also developed a productivity peer group consisting of the subset of the full sample of utilities which experienced customer growth during the full sample period which was similar to the brisk growth which Alberta distributors are likely to experience during the indexing years of the next PBR plan. In this exercise, we first calculated the recent historical trends in the total numbers of customers served by larger Alberta gas and electric power distributors. We then forecasted the total gas and electric customer growth trends over the 2018-23 sample period by adjusting the historical trends for the difference between Alberta's recent historical population growth trend and a forecast of the same for the 2018-23 period. The resulting customer trend forecasts are 1.77% for Alberta power distributors and 1.60% for Alberta gas

[63] Capital productivity trends tend to be similar to MFP trends due to the heavy weight on capital in the indexes.

distributors. This pace of customer growth, while slower than in Alberta's recent past, is roughly double that of the full U.S. productivity sample.

We then calculated average productivity trends for the subset of the full sample of utilities which averaged 1.7% customer growth over the full sample period. This peer group contains 21 utilities that are identified in Table 4. Most of the utilities in this group serve economies in the western and southeastern states that had brisk growth trends.

Results for the rapid growth peer group are presented in Table 5c and Figure 1. It can be seen that, over the full sample period, these utilities averaged 1.38% growth in O&M productivity, 0.59% growth in capital productivity, and 0.80% growth in multifactor productivity. The O&M and multifactor productivity of these utilities has accelerated on average since 2008.

A Mountain West group was also constructed. This consists of ten utilities with service territories in the Pacific Northwest and intermountain West. These utilities averaged 1.85% customer growth over the full sample period. They averaged 1.57% O&M productivity growth, 0.74% capital productivity growth, and 0.88% multifactor productivity growth.

We recommend that trends based on our rapid growth peer group be used in the design of next generation PBR plans. The results can be used to set X factors or to reduce capital tracker revenue.[64] We may upgrade these calculations in rebuttal testimony to reflect better forecasts of customer growth and estimates of output differentials that are pertinent to power distributor X factors.

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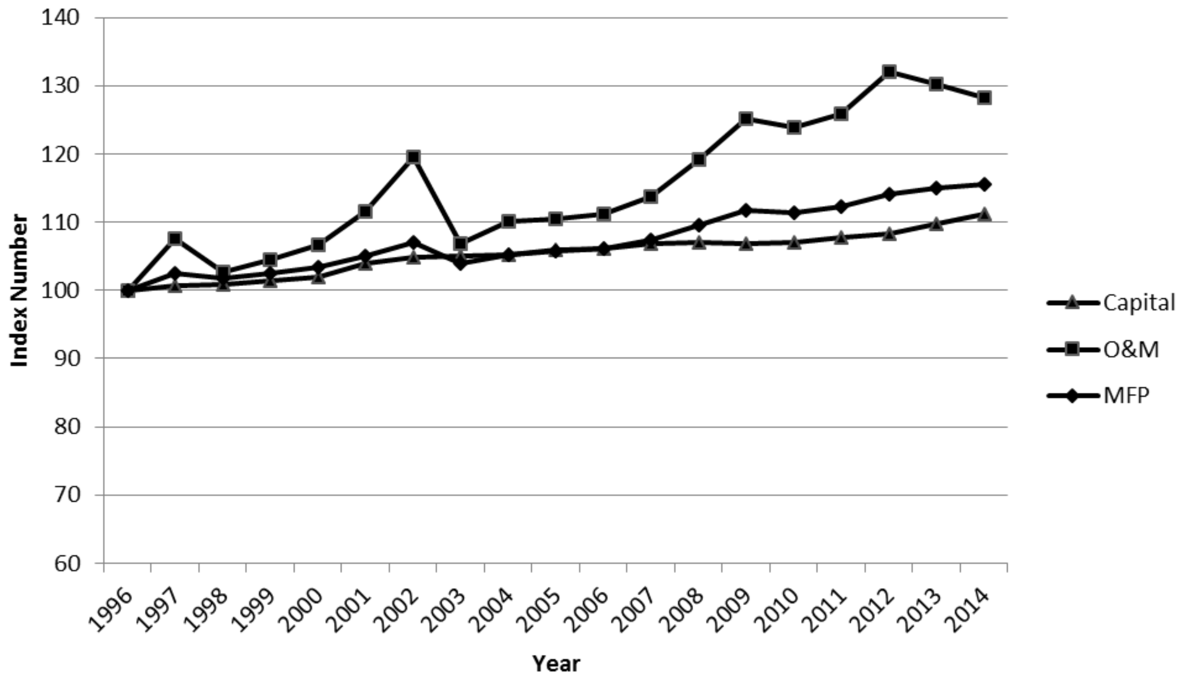
[64] For example, the difference in revenue escalation using X factors based on the rapid-growth peer group and the full sample could be used to deny a portion of capital tracker requests.

Table 5c U.S. Power Distribution Productivity Trends: Rapid Growth Sample[65]

Year	**Output**	**Input**	**Productivity**		
			O&M	**Capital**	**MFP**
	[A]	[B]			[C=A-B]
1997	2.63%	0.15%	7.25%	0.73%	2.47%
1998	2.78%	3.55%	-4.53%	0.16%	-0.77%
1999	2.44%	1.65%	1.73%	0.48%	0.79%
2000	2.33%	1.48%	2.06%	0.50%	0.85%
2001	2.04%	0.54%	4.35%	1.92%	1.51%
2002	2.10%	0.13%	6.92%	1.00%	1.97%
2003	2.12%	5.05%	-11.24%	0.20%	-2.93%
2004	2.10%	0.94%	3.13%	0.11%	1.16%
2005	2.73%	2.24%	0.30%	0.61%	0.49%
2006	1.81%	1.41%	0.69%	0.28%	0.41%
2007	2.00%	0.78%	2.25%	0.63%	1.22%
2008	1.10%	-0.89%	4.66%	0.16%	1.99%
2009	0.53%	-1.45%	4.88%	-0.10%	1.99%
2010	0.49%	0.81%	-1.09%	0.03%	-0.32%
2011	0.51%	-0.26%	1.61%	0.68%	0.77%
2012	0.73%	-0.83%	4.88%	0.65%	1.56%
2013	1.01%	0.26%	-1.47%	1.25%	0.74%
2014	1.19%	0.69%	-1.47%	1.28%	0.50%
Average Annual Growth Rates					
1997-2014	**1.70%**	**0.90%**	**1.38%**	**0.59%**	**0.80%**
1997-2007	**2.28%**	**1.63%**	**1.17%**	**0.60%**	**0.65%**
2008-2014	**0.79%**	**-0.24%**	**1.71%**	**0.56%**	**1.03%**

[65] Annual growth rates are calculated logarithmically.

Figure 1 **Productivity Trends for Rapid Growth Distributors**



4.6. Precedents

Table 6 provides a compilation of precedents for approved X factors in North American PBR plans. Some regulators have expressly ruled on utility productivity trends and/or the appropriate stretch factor in addition to the X factors.

Here are some notable results of the survey.

- The average productivity trend acknowledged for U.S. power distributors is 0.76%.
- The average productivity trend acknowledged for U.S. gas distributors is 0.63%.
- The average X factor approved for U.S. power distributors is 1.20%.
- The average X factor approved for U.S. gas distributors is 1.11%.
- The average approved stretch factor is 0.42%.

Table 6 Precedents for Approved X factors in North American PBR Plans

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Inflation Measure	Acknowledged Productivity Trend	Stretch Factor [2]	X-Factor [3]
Bundled Power Service	PacifiCorp (I)	California	1994-1997, extended to 1999	Price Cap	Industry-specific	1.40%	NA	1.40%
Bundled Power Service	Central Maine Power (I)	Maine	1995-1999	Price Cap	GDPPI	NA	NA	0.9% (Average)
Gas Distribution	Southern California Gas	California	1997-2002	Revenue Cap	Industry-specific	0.50%	0.80% (Average)	2.3% (Average)
Power Distribution	Southern California Edison	California	1997-2002	Price Cap	CPI	NA	NA	1.48% (Average)
Gas Distribution	Boston Gas (I)	Massachusetts	1997-2003	Price Cap	GDPPI	0.40%	0.50%	0.50%
Power Distribution	Bangor Hydro Electric (I)	Maine	1998-2000	Price Cap	GDPPI	NA	NA	1.20%
Power Distribution	PacifiCorp (II)	Oregon	1998-2001	Revenue Cap	GDPPI	NA	NA	0.30%
Gas Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.68%	0.55% (Average)	1.23% (Average)
Power Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.92%	0.55% (Average)	1.47% (Average)
Power Distribution	All Ontario distributors	Ontario	2000-2003	Price Cap	Industry-specific	0.86%	0.25%	1.50%
Gas Distribution	Bangor Gas	Maine	2000-2009, extended to 2012	Price Cap	GDPPI	NA	NA	0.33% (Average)
Gas Distribution	Union Gas	Ontario	2001-2003	Price Cap	GDPPI	NA	NA	2.50%
Power Distribution	Central Maine Power (II)	Maine	2001-2007	Price Cap	GDPPI	NA	NA	2.57% (Average)
Power Distribution	Southern California Edison	California	2002-2003	Revenue Cap	CPI	NA	NA	1.60%
Power Distribution	EPCOR (I)	Alberta	2002-2005, Terminated at end of 2003	Price Cap	Industry-Specific	NA	NA	15% * Inflation
Gas Distribution	Berkshire Gas	Massachusetts	2002-2011	Price Cap	GDPPI	0.40%	1.00%	1.00%
Gas Distribution	BIackstone Gas	Massachusetts	2004-2009	Price Cap	GDPPI	NA	NA	0.50%
Gas Distribution	Terasen Gas	British Columbia	2004-2009	Revenue Cap	CPI	NA	NA	63% x Inflation (Average)
Gas Distribution	Boston Gas (II)	Massachusetts	2004-2013, terminated in 2010	Price Cap	GDPPI	0.58%	0.30%	0.41%
Power Distribution	All Ontario Distributors	Ontario	2006-2009	Price Cap	GDPIPI	NA	NA	1.00%
Power Distribution	Nstar	Massachusetts	2006-2012	Price Cap	GDPPI	NA	NA	0.63% (Average)
Gas Distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	Price Cap	GDPPI	0.58%	0.40%	0.51%
Power Distribution	ENMAX	Alberta	2007-2013	Price Cap	Industry-specific	0.80%	0.40%	1.20%
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	47% x Inflation (Average)
Gas Distribution	Union Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	1.82%
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	Revenue Cap	CPI	1.03%	NA	1.00%
Power Distribution	Central Maine Power (III)	Maine	2009-2013	Price Cap	GDPPI	NA	NA	1.00%
Power Distribution	All Ontario Distributors	Ontario	2010-2013	Price Cap	GDPPI	0.72%	0.40% (Average Across Firms)	1.12% (Average Across Firms)
Power Distribution	Green Mountain Power	Vermont	2010-2013	Revenue Cap	CPI	NA	NA	1.00%

Table 6 (continued)

Precedents for Approved X factors in North American PBR Plans

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Inflation Measure	Acknowledged Productivity Trend	Stretch Factor [2]	X-Factor [3]
Power Distribution	ATCO Electric, EPCOR, FortisAlberta	Alberta	2013-2017	Price Cap	Industry-specific	0.96%	0.20%	1.16%
Gas Distribution	All Distributors	Alberta	2013-2017	Revenue Cap	Industry-specific	0.96%	0.20%	1.16%
Power Distribution	Green Mountain Power	Vermont	2014-2017	Revenue Cap	CPI	NA	NA	1.00%
Gas Distribution	Union Gas	Ontario	2014-2018	Revenue Cap	GDPPI	NA	NA	60% x Inflation
Power Distribution	All Distributors except those who opt out	Ontario	2014-2018	Price Cap	Industry-specific	0.00%	Range of 0% to 0.6%	Range of 0% to 0.6%
Bundled Power Service	FortisBC	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.93%	0.10%	1.03%
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.90%	0.20%	1.10%

Averages*	**Gas Distributors**	**0.63%**	**0.49%**	**1.11%**
	Electric Utilities	**0.85%**	**0.32%**	**1.19%**
	Power Distributors	**0.76%**	**0.36%**	**1.20%**
	All Utilities	**0.74%**	**0.42%**	**1.16%**

*Averages exclude X factors that are percentages of inflation.

[1] Shaded plans have expired.

[2] Some approved X factors are not explicitly constructed from such components as a base productivity trend and a stretch factor. Many of these are the product of settlements.

[3] X factors may not be the sum of the acknowledged productivity trend and the stretch factor, where these are itemized, for the following reasons: (1) a macroeconomic inflation measure is employed in the attrition relief mechanism, (2) a revenue cap index may not include a stand-alone scale variable and this can reduce X, or (3) the X factor may incorporate additional adjustments to account for special business conditions.

4.7. Stretch Factors

Utilities have more potential to increase their productivity growth to the extent that their existing operations are inefficient. The potential to improve efficiency therefore merits consideration in PBR plan design, just as special considerations that occasion extra capital revenue do. There is no credible argument for setting stretch factors at zero just because utilities have operated under one term of PBR.

- The frequent rate cases that preceded PBR in Alberta weakened incentives for cost containment.

- The performance incentives generated by first-generation Alberta PBR are not likely to be strong enough to eliminate the accumulated inefficiencies of utilities. The weak incentives to contain capex under the current PBR system are a notable concern.
- Some Alberta utilities may in fact be LESS efficient at the end of five years due to high levels of capex.
- Even if incentives in first generation PBR were much stronger, it is notable that companies that have operated for years in competitive markets have widely varying degrees of operating efficiency.

Statistical benchmarking should be considered as a means of setting stretch factors. Benchmarking can address O&M expenses, capital cost, total cost, and reliability. There are several solid arguments for beginning routine benchmarking in Alberta.

- An implicit presumption by distributors that their operations are efficient permits them to argue that they are entitled to every penny of their forecasted capital cost shortfalls in order to "keep the lights on." Benchmarking can help identify inefficient utilities and provides an empirical basis for higher stretch factors where needed.
- Benchmarking is routinely used to set stretch factors for power distributors in Ontario, even though distributors there are in their *fourth* generation of PBR. Benchmarking is also extensively used by Australian and British regulators. These precedents are noteworthy since these regulators have extensive PBR experience. PEG Research has in the last two years prepared transnational power distribution cost benchmarking studies for both the Australia Energy Regulator and the Ontario Energy Board, and benchmarks the costs of all Ontario Power distributors each year using the latest available Ontario data.
- The AUC may have more time and budget to consider benchmarking evidence if the base productivity trend for second generation plans is resolved in this generic proceeding.

4.8. Incentive Compatible Menus

Incentive-compatible menus, proposed in the last generic PBR proceeding in Alberta by UCA witnesses Cronin and Motluk and rejected by the Commission, remain a promising tool for PBR plan design. These menus have the goal of incentivizing utilities to make reasonable forecasts of their attainable cost trajectories, and share benefits with customers. Menu options could vary with the X factor and another financially important provision such as the division of earnings variances between the utility and its customers in earnings sharing mechanisms. Incentive compatible menus are currently used in an "information quality incentive" to set future revenue requirements of gas and electric power distributors by the British regulator Ofgem.

We recommend that the AUC consider use of incentive-compatible menus in this and future plans. It must be emphasized, however, that development of menus that share value with customers is costly since it requires the AUC to develop reliable independent views on efficient costs and cost trends. In the British plans, for example, the opinion of the regulator about a utility's revenue carries a roughly 75% weight. The AUC may not develop this capability in the course of this proceeding. PEG Research has done considerable research on the menu approach and could fashion a reasonable menu based on our research. The ability to adopt incentive compatible menus in the future will be bolstered to the extent that the AUC takes steps soon to encourage independent engineering and benchmarking studies and stronger, more integrated planning procedures.

5. Rebasing Provisions

5.1. Rate Cases

A full rebasing of rates to actual costs is probably needed in the new plan. Arguments against full rebasing include the higher regulatory cost required and the weakening of performance incentives. Arguments in favor of a full rebasing include the following.

- The current plan has inadvertently tended to overcompensate utilities. Revenue for costs subject to indexing should be reset at actual cost.
- A rebasing would provide an opportunity to introduce statistical benchmarking. The benchmarking could apply to the utility's proposed forward test year, discouraging gaming. We have benchmarked forward test year costs for clients on several occasions.

An important issue in rebasing is how the new revenue requirement is related to recent historical costs. Utilities may defer certain expenses during the current plan and then ask for higher budgets in the forward test year. This would deprive customers of benefits they were promised under PBR. The Commission has recognized that this is a potential issue in capital tracker application and should be vigilant for such strategies in rebasing applications as well.

Consideration should be paid to staggering rebasings by 9-12 months to permit a greater focus on each utility's rebasing. Alternatively, 2 applications could be considered each year. The staggering of rebasings is standard practice in Ontario and California.

5.2. Efficiency Carryover Mechanisms

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

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

We discuss each group of issues in turn.

Calculation of Efficiency Carryovers

One issue in the calculation of efficiency carryovers is the areas of performance that are considered for carryover. Regulators may also wish to focus on components of cost, such as opex and capex, over which utilities have a lot of control in the short run and ignore areas over which they have less control, such as the cost of older plant. Another consideration is the ease with which efficiency can be measured. It may be deemed easier, for example, to appraise opex efficiency than capex efficiency.

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

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

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

Where this is so, the revenue requirement is itself a candidate benchmark, and is described as such in some rate plans that have efficiency carryover mechanisms.[66]

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

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

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

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

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

How Efficiencies are Carried Over

How efficiencies are carried over depends on how revenue requirements are set in the succeeding rate plan. In many jurisdictions, revenue requirements are commonly established in the first year of a rate plan and then escalated by an external attrition relief mechanism. It can make sense, then, to treat the efficiency carryover as a supplement to the first year revenue requirement and there is no need to provide for its preservation in later years of the plan. However, some plans expressly guarantee companies a share of the efficiency gains achieved in any one year for a period of five years. Implementation of this requires that efficiency carryovers vary by the years of a rate plan. In year one, for example, there may be carryovers for the last five years of the proceeding plan. In year five, on the other hand, there may only be a carryover from year five of the previous plan.

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

Precedents

Experience around the world with efficiency carryover mechanisms has been less extensive than experience with some other MRP features we have discussed. In addition to the AUC, Australia has been a leader and has used these mechanisms in both power transmission and distribution regulation. National Grid has secured efficiency carryover mechanisms for several power distribution utilities in the Northeast U.S.

Case Study: National Grid (Massachusetts)

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

The U.S. acquisitions sparked development of several MRPs that included creative efficiency carryover mechanisms. New England Electric System and Eastern Utilities Associates were New England electric utilities in the process of merging when they were acquired by National Grid ("Grid"). In 2000, the Massachusetts Department of Telecommunications and Energy ("DTE") approved a settlement resolving a host of regulatory issues. The settlement detailed a "performance based" rate plan under which the Massachusetts distribution utilities of the two companies (Massachusetts Electric and Nantucket Electric) would operate.[67] The plan had a ten-year term. Rates for distribution services were reduced at the outset of the plan. In the absence of a rate filing, the plan provided that the rates would remain at the reduced level for five years and then be escalated, over a 4.75-year "Rate Index Period", by a "Regional Index" of the distribution rates charged by northeast power distributors. A supplemental award penalty mechanism encouraged the maintenance of service quality.

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

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[67] See "Rate Plan Settlement," November 29, 1999. The DTE approved the settlement in D.T.E. 99-47.

"Earned Savings" = Distribution revenue under rates applicable in March 2009

- pro forma cost of service ("COS") (which includes applicable income taxes but not acquisition premiums or transactions costs).

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

Under these terms, if National Grid filed a rate case in 2010 based on a 2009 test year and its cost of service was $30 million less than its base rate revenue in that year it would not be required to reduce rates.[68] If its COS was $80 million below base rate revenue, it would be required to reduce rates by only $14 million.

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

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

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

At the end of the plan period in 2009, a large revenue requirement increase was requested, which was rationalized in part by the need to replace aging infrastructure. The filing

[68] Massachusetts does not have forward test years.

included a revenue decoupling plan (in conformance with evolving DTE policy) that featured a revenue cap of hybrid form. There would be expedited annual approval of future capital spending budgets in what would amount to "mini" rate cases.

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

Application to Alberta

The current ECM is flawed since the average surplus earnings achieved during first-generation PBR is a poor proxy for lasting productivity gains. For example, surplus earnings may reflect a suboptimal PBR plan or a strategy of deferring certain expenses and then asking for supplemental compensation in the rebasing or the capital trackers of next-generation plans.

We recommend that the Commission consider a new ECM for second generation PBR either in this generic proceeding or subsequent proceedings. Fresh thinking is needed. Mechanisms should be designed to reward good value to customers in the rates of future MRPs rather than focusing on earnings in the expiring MRP.

Appendix

A.1 Analyzing the Overcompensation Problem

We analyze the overcompensation problem in the context of revenue cap indexes similar to those the AUC uses to regulate gas distributors.[69] Allowed revenue ("R") is escalated for input price inflation ("I") and customer growth ("ΔN") less an X factor that is the sum of a stretch factor and the multifactor productivity trend of a peer group ("$\Delta\overline{MFP}$").

The growth in a utility's revenue can be shown to be a revenue-share-weighted average of the growth in its capital tracker revenue ("R_{KT}") and other revenue ("R_O").[70] The tracker effectively sets growth in revenue for tracked cost equal to the growth in that cost. Thus

$$\Delta R = sr_{KT} \bullet \Delta R_{KT} + sr_O \bullet \Delta R_O$$

$$= sr_{KT} \bullet ([I - (\Delta\overline{MFP} + Stretch) + \Delta N] + \{\Delta C_{KT} - [I - (\Delta\overline{MFP} + Stretch) + \Delta N]\})$$

$$+ sr_O \bullet [I - (\Delta\overline{MFP} + Stretch) + \Delta N]$$

$$= sr_{KT} \bullet \Delta C_{KT} + sr_O \bullet [I - (\Delta\overline{MFP} + Stretch) + \Delta N]. \quad [A1]$$

Here sr_{KT} is the share of revenue addressed by capital trackers, sr_O is the share of revenue not addressed by capital trackers, and ΔC_{KT} is the change in cost that is addressed by capital trackers.

Suppose now that a utility's cost growth conforms to the formula

$$\Delta C = I - \Delta MFP + \Delta N. \quad [A2]$$

[69] Analogous reasoning applies to the price caps used in Alberta power distributor regulation.
[70] We simplify this analysis by excluding consideration of tracked O&M expenses.

Multifactor productivity growth can be shown to be a cost-share-weighted average of the partial factor productivity ("PFP") growth rates of tracked capital and of all other inputs

$$\Delta MFP = sc_{KT} \bullet \Delta PFP_{KT} + sc_{O} \bullet \Delta PFP_{O}. \qquad [A3]$$

A utility's profitability can be measured as the ratio of its revenue to its cost. Equations [A1] - [A3] then imply that the growth of a utility's rate of return is given by

$$\Delta R/C = \Delta R - \Delta C$$

$$= sr_{O} \bullet [\Delta PFP_{O} - (\Delta \overline{MFP} + Stretch)]. \qquad [A4]$$

The key driver of earnings is thus the difference between the X factor and the utility's productivity in managing non-tracked costs. The potential for overearnings must be considered in all years and not just the years in which the capital tracker is operative.

The productivity growth that the utility achieves in the management of other costs can be decomposed into the PFP that the productivity peer group achieves in the management of like inputs ("$\overline{PFP_{O}}$") and the success the utility achieves in exceeding the industry PFP_{O} trend. Thus

$$\Delta R - \Delta C = sr_{O} \bullet [(\Delta \overline{PFP_{O}} - \Delta \overline{MFP_{O}}) + (\Delta PFP_{O} - \Delta \overline{PFP_{O}})]. \qquad [A5]$$

We are concerned with the tendency of $\Delta \overline{PFP_{O}}$ to exceed $\Delta \overline{MFP_{O}}$ since this can be used to finance capex.

Note finally that

$$\Delta R = sr_{KT} \bullet (I - \Delta PFP_{KT} + \Delta N) + sr_{O} \bullet (I - \Delta \overline{MFP} + \Delta N)$$

$$= I - (sr_{KT} \bullet \Delta PFP_{KT} + sr_{O} \bullet \Delta \overline{MFP}) + \Delta N \qquad [A6]$$

Thus, this PBR system clearly does not guarantee customers the benefit of the peer group MFP trend.

A.2 Capital Trackers in Other Canadian Jurisdictions

A.2.1 British Columbia

In 2014 the British Columbia Utilities Commission ("BCUC") approved a return to PBR for FortisBC Energy (formerly Terasen Gas) and FortisBC (formerly West Kootenay Power) after several years of more traditional regulation. Unlike PBR plans in many jurisdictions, these plans escalate budgets for O&M expenses and certain capital *expenditures* with separate formulas that are based on inflation and the growth of operating scale less an X factor. FortisBC has one formula applying to all untracked capex. This formula features the number of customers as the scale escalator. FortisBC Energy has one formula for growth capex and a second formula for sustainment and other untracked capex. These use the service line additions and the number of customers, respectively, as the scale escalators.

The formulas are designed to escalate the allowed capex of projects that are smaller and more routine and predictable. Capital costs for projects that are larger, more unusual in nature, and less predictable are tracked, along with the cost of all older plant. Projects that have been approved for capital cost tracking to date include FortisBC Energy's biomethane projects, FortisBC's deployment of AMI, and both companies' capitalized pensions and other post-employment benefits.

Each year the companies' rates are revised to reflect the cost growth resulting from the formulas and trackers through an annual rate review. In these reviews, both formula-based plant additions and tracked plant additions are added to the rate base. Actual plant additions are fully reflected in the rate base only in the rebasing at the end of the plan.[71] The rate base is also updated in these proceedings to reflect the falling value of old plant due to depreciation.

[71] A limited true up of the rate base for the difference between actual and formulaic capital additions is required if there is a 15% variance between formula and actual plant additions over 2 years or a 10% variance in a single year.

By including the impact of depreciation of the existing rate base, the impact of capex on the revenue requirement is lessened substantially. For example, if the entirety of FortisBC Energy's 2015 plant additions had been added to rate base without taking account of the depreciation of the existing rate base, the increase in the revenue requirement to reflect the application of the allowed return on equity to the change in rate base would have been four or five times larger than the $1.5 million requested by the company.

Despite accepting the use of trackers for some capital costs, the BCUC acknowledged some challenges in tracker design.

> In the Panel's view, the more capital excluded from formula spending, the fewer benefits of PBR accrue to ratepayers and shareholders alike. Excluding significant amounts of capital [from indexing] reduces the ability of the utility to achieve operating efficiencies. However, it also provides opportunities for a utility to game the system, such as by combining smaller projects into larger projects that will be excluded from the formula.[72]
>
> To the extent that a project results in a reduction of maintenance expenditures, the utility will have the opportunity to underspend its [index-based] maintenance spending envelope. The Panel recommends that, if capital associated with a particular CPCN is excluded from the [escalation] formula, the CPCN review of that project should include an assessment by the Commission of any potential impact of the project on O&M. If appropriate, an adjustment to the formula based O&M spending envelope should then be made.[73]

A substantial effort was undertaken to determine tracker eligibility criteria for capex.[74] In its 2014 decision approving the PBR plans, the BCUC rejected the use of CPCN eligibility criteria to determine tracker eligibility, because these criteria address concerns that are

[72] British Columbia Utilities Commission (2014), In the Matter of FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 Decision, September 15, p. 176.

[73] *Ibid.,* p. 182.

[74] The BCUC refers to these criteria as capital exclusion criteria, meaning exclusion from formulaic escalators.

different from determining which capital projects should be tracked under PBR and have loopholes that would potentially allow small capital projects to be tracked. Nevertheless, pending the approval of a better materiality threshold, the BCUC approved the CPCN criteria as the tracker eligibility criteria on an interim basis.

The BCUC began a proceeding to finalize the tracker eligibility criteria and rendered its decision in July 2015. The tracker eligibility criteria approved in this decision was a materiality threshold based on the updated CPCN materiality thresholds of $20 million for FortisBC and $15 million for FortisBC Energy for individual projects.[75] The BCUC rejected proposals for additional tracker eligibility criteria.

This decision also addressed several of the BCUC's concerns about possible gaming and double counting issues. The companies are required to show in each capital tracker application that the eligibility criteria had not been met by a combination of smaller projects that would normally be funded by the index-based escalators. Individual application proceedings will include an opportunity for the impact of the project on O&M expenses to be addressed.

A.2.2 Ontario

Incentive Regulation Mechanisms

Most power distributors in Ontario operate under PBR plans called incentive regulation mechanisms ("IRMs"). In these plans, rates are escalated by price cap indexes with I-X formulas. The X factor for each utility is the sum of a common base productivity trend and a custom stretch factor that reflects the results of a statistical benchmarking study that is updated annually. The base productivity trend is the historical MFP trend of a power distributor peer group.

[75] FortisBC Energy's biomethane projects were not required to meet this threshold in order to have the projects' costs tracked.

Incremental Capital Module In 2008, the Ontario Energy Board ("OEB") approved its first Incremental Capital Module ("ICM") framework. ICMs provide supplemental revenue for capital expenditures. ICMs have been included as part of the OEB's 3rd and 4th generation IRMs.

Eligibility Criteria In order to receive approval of an ICM, proposed projects must meet certain conditions.

Causation: Proposed capex must be directly related to a non-discretionary driver and outside the base upon which rates were derived. To meet the causation condition, a utility must first explain the underlying causes of the need for additional capex and show that the requested funding through an ICM only addresses those causes. The driver must be of the sort that does not allow for discretion in the timing of the capex. To show that the capex is outside of the base upon which rates are derived, the utility must also show that the capex hasn't already been funded through base rates or the expansion of service to new customers.

Prudence: Capex incurred must be prudent and the most cost-effective option for ratepayers.

Materiality: The amount of capex needed must exceed a capex-to-depreciation-expense threshold defined by the OEB and clearly have a significant influence on the operation of the distributor. The threshold is applied on an aggregate basis. Only the costs of the capex above the materiality threshold are eligible for recovery through the ICM.

The original threshold formula was:

$$Threshold\ Value = \frac{CAPEX}{d} = 1 + \frac{RB}{d} * \left(g + PCI * (1 + g)\right) + 20\% \quad [A7]$$

where *CAPEX* is forecasted total capital expenditures, *d* is the depreciation expense included in base rates, *RB* is the rate base included in base rates, *g* is revenue growth due to changes in billing determinants, and *PCI* is the growth in the price cap index.[76] This formula may be expressed equivalently as

$$CAPEX = d + RB * \left(g + PCI * (1 + g)\right) + 20\%$$

and can be shown to combine a materiality test with a double counting test that is similar in spirit to the test used in Alberta. The chief differences in application are three fold. First, the OEB's materiality threshold is based around the funding levels of capex rather than the revenue requirements resulting from capex. Second, the OEB's calculation of double counting is done on an aggregate basis rather than at the project level. Third, the OEB included a 20% deadband to prevent marginal applications of the ICM.

ICM Operation

If a project qualifies for the ICM, recovery of amounts approved under the ICM is realized via rate riders. Distributors who receive approval for rate relief through an ICM are required to report their actual capex annually. Cost overruns are reviewed for prudence in rate rebasing proceedings. If the overrun is prudently incurred, the amount will be included in rates. Underspends will result in refunds to ratepayers.

ICM Use

To date, less than one quarter of the approximately 70 Ontario power distributors have received approval for ICMs. ICMs are typically used to address the costs of a handful of large capital projects. For example, in a September 2014 Report of the Board, the OEB noted that

[76] Formulas in this section differ from those in other sections due to the OEB's use of arithmetic growth rates rather than logarithmic growth rates.

“nine out of the 13 ICM applications filed have included transformer-related assets as the focal point of the funding request.”[77]

Updates

The ICM has evolved over the years. Early criteria for the ICM included requirements for a project to be extraordinary and unanticipated. These requirements were set aside in 2013. In 2014, the Board renamed the causation criteria “need,” and revised it to include a means test, which prevents companies overearning by 300 basis points or more from being allowed supplemental capital funding. This criterion was also revised to allow the costs resulting from discretionary projects to be included in an ICM. The OEB also clarified that the ICM should only apply to discrete projects that are not part of typical annual capital programs.

The materiality threshold has also been revised. In 2013, a project-specific materiality threshold was established that excluded specific projects on the basis that they were minor expenditures in comparison to the overall capital budget. In 2016, the OEB revised the materiality threshold in order to address ICMs covering more than one year. The new formula is:

Threshold Value =

$$\frac{CAPEX}{d} = \left[1 + \frac{RB}{d} * \left(g + PCI * (1+g)\right)\right] * [(1+g) * (1+PCI)]^{n-1} + 10\% \quad \text{[A8]}$$

where *n* is the number of years since rebasing. These changes lower the deadband above the ratio of capex to depreciation expense that can normally be funded by the OEB’s price caps, and extend the formula to address capex planned over a multiyear period by continuing to inflate the expected ratio of capex to depreciation expense by the growth in billing

[77] Ontario Energy Board (2014), Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, filed in Case EB-2014-0219, September 18, p. 7.

determinants and the price cap. One reason for the inclusion of multiple years of capital projects in the ICM and ACM was to reduce the bunching of capital projects around the rate rebasing year.

In 2014, the Board also approved an alternative means of obtaining supplemental funding for capital called the Advanced Capital Module. This allows utilities to apply in advance at the time of their cost of service rebasing for supplemental funding of projects detailed in their five-year Distribution System Plans ("DSPs"). Reviews of ACM requests would then coincide with a review of proposed DSP projects, allowing for greater regulatory efficiency. The ICM remains available for projects not included in the DSP as well as those in the DSP whose eligibility for supplemental funding could not be determined at the time of the rate case. The criteria for ACM approval are the same as those for ICMs.

The current generation of PBR plans in Ontario has two additional options to address the diversity of Ontario distributors. One option, Custom IR, is designed for distributors that expect to undertake large capital projects over several years. This option allows distributors to develop MRPs based on forecasts of total O&M and capital spending. These forecasts must be supported by benchmarking evidence and should be informed by the OEB-sponsored productivity and benchmarking analyses.

The Annual IR index is the second option and is designed to suit distributors that do not expect to undertake large capital projects. This option features a price cap index with an I-X formula, but the X factor is fixed to reflect the highest 4th generation IR stretch factor for all plan years. Utilities that choose the Annual IR index do not have the option to request an ICM.

A.3 Further Details of the Productivity Research

This section contains more technical details of our empirical research for the CCA. We first discuss our input quantity and productivity indexes, respectively. We then turn to the calculation of capital cost.

A.3.1 Input Quantity Indexes

The quantity subindex for labor was the ratio of salary and wage expenses to a regionalized salary and wage labor price index.[78] The growth rate of the labor price index was calculated for most years as the growth rate of the national employment cost index ("ECI") for the salaries and wages of the utility sector plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole. The quantity subindex for M&S inputs was the ratio of the expenses for these inputs to an M&S price index developed by PEG from producer price subindexes obtained from the BLS. The capital quantity indexes are discussed below.

The growth rate of each *summary* input quantity index was defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Each summary input quantity index was of chain-weighted Törnqvist form.[79] This means that its annual growth rate was determined by the following general formula:

$$\ln\left(\frac{Inputs_t}{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad \text{[A9]}$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

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

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

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[78] Utilities no longer report on their FERC Form 1 the number of workers that they employ.

[79] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

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

A.3.2 Productivity Growth Rates and Trends

The annual growth rate of each company's productivity index is given by the formula

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}} \right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}} \right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right). \quad [A10]$$

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

A.3.3 Capital Cost Measurement

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

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \quad [A11]$$

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index measures the trend in the hypothetical price of capital services from the assets in a competitive rental market.

In our power distribution research for the CCA there are two categories of plant: power distribution plant and general plant. The power distribution plant data from FERC Form 1 included the value of plant for local delivery and metering.

Geometric Decay

In constructing capital quantity indexes using the geometric decay approach, we took 1964 as the benchmark year. The values for these indexes in the benchmark year are based on the net value of plant as reported in the FERC Form 1. We estimated the benchmark year (inflation adjusted) value of net plant by dividing this book value by an average of the values of an index of utility construction cost for a period ending in the benchmark year. The construction cost index (WKA_t) was the applicable regional Handy-Whitman index of utility construction costs for the relevant asset category.[80]

The following formula was used to compute subsequent values of the capital quantity index for an asset class:

$$XK_{j,t} = (1-d)\cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad \text{[A12]}$$

Here, the parameter *d* is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The full formula for the capital service price indexes used in the research was

$$WKS_{j,t} = [CK_{j,t}^{Taxes} / XK_{j,t-1}] + d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad \text{[A13]}$$

The first term in the expression corresponds to taxes and franchise fees. The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

[80] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

COS

Derivation Here is the mathematical derivation of the formulas we used in our COS capital cost specification. For each year, t, of the sample period let

ck_t = Total non-tax cost of capital

$ck_t^{Opportunity}$ = Opportunity cost of capital

$ck_t^{Depreciation}$ = Depreciation cost of capital

VK_{t-s}^{add} = Gross value of plant installed in year t-s

WKA_{t-s} = Unit cost of plant installed in year t-s (the "price" of capital assets)

a_{t-s} = Quantity of plant additions in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$

xk_t = Total quantity of plant available for use and that results in year t costs

xk_t^{t-s} = Quantity of plant available for use in year t that remains from plant additions in year t-s

VK_t = Total value of plant at the end of the previous year

N = Service life of utility plant

r_t = Rate of return (cost of funds)

WKS_t = Price of capital service

A few assumptions are made for convenience in the derivation to follow:

(1) All kinds of plant have the same service life N.

(2) Full annual depreciation and opportunity cost are incurred in year t on the amount of plant remaining at the end of year t-1, as well as on any plant added in year t.

(3) The ARM is not designed to recover changes in taxes.

Consider, now, that the non-tax cost of capital under cost of service regulation is the sum of depreciation and the opportunity cost paid out to bond and equity holders.

$$ck_t = ck_t^{opportunity} + ck_t^{depreciation}$$

Assuming straight line depreciation and book valuation of utility plant,

$$\begin{aligned} ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot r_t + \sum_{s=0}^{N-1} WKA_{t-s} (1/N) \cdot a_{t-s} \\ &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{(1/N) \cdot a_{t-s}}{xk_t}. \end{aligned} \quad [A14]$$

where, as per assumption 2 above,

$$xk_t = \sum_{s=0}^{N-1} xk_t^{t-s}. \quad [A15]$$

Under straight line depreciation we posit that in the interval $[(t-(N-1)),(t-1)]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \quad [A16]$$

Combining [A15] and [A16] we obtain a capital quantity index that is a perpetual inventory equation.

$$xk_t = \sum_{s=0}^{N-1} \frac{N-s}{N} \cdot a_{t-s}. \quad [A17]$$

The size of the addition in year t-s of the interval (t-1, t-N) can be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \quad [A18]$$

Relations [A14] and [A18] together imply that,

$$ck_t = xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t \; + \; xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \qquad \text{[A19]}$$
$$= xk_t \cdot WKS_t .$$

Here,

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t \; + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} . \qquad \text{[A20]}$$

Relation [A19] reveals that the cost of capital under traditional utility accounting can be decomposed into a capital price index and a capital quantity index. The capital service price in a given year reflects a weighted average of the capital asset prices in the N most recent years (including the current year). The weight for each year, t-s, is the estimated share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year. This share will be larger the more recent the plant addition year and the larger were the plant additions made in that year. The average asset price rises over time as the price for each of the N years is replaced with the higher price for the following year. It will reflect inflation that occurred in numerous past years as well as current inflation. Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.[81]

Implementation Relations [A17] and [A20] were calculated for each sampled utility for two categories of assets: distribution plant and general plant. In these calculations, regional Handy-Whitman indexes of power distribution construction costs were used as the asset price indexes.[82] In the distribution index the value of N was set at 44. The value of N for general

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[81] Recall that the depreciation rate is constant under the geometric decay approach to capital costing.

[82] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

plant was set at 16 years. The values for gross plant additions VK_{t-s}^{add} in the years 1965-2011 were drawn from FERC Form 1. Values for earlier years were imputed using data on the net value of plant in 1964 and the construction cost index values for those years.

The calculation of [A20] requires, in addition, an estimate of the rate of return.[83] We employed a weighted average of RORs for debt and equity. For debt we calculated the average embedded cost of debt for a large sample of power distributors, using data from FERC Form 1. For each distributor we calculated the ratio of interest expenses on long-term debt to the value of long-term debt outstanding. The rate of return on equity was the average approved each year for electric utilities in rate cases as reported by the Edison Electric Institute.

A.3.4 Alberta Customer Trends

Table A1 details our work on customer growth trends for Alberta gas and electricity distributors. Annual growth rates are calculated logarithmically. The years for which data represent forecasts are shaded. We link our customer growth forecasts to recent projections of Alberta population growth released in 2015 by the Alberta Treasury Board and Finance.

The leftmost three columns of the table show the projected population growth trends for low, medium, and high growth scenarios, along with the historical trends for the 2005-14 period. To the right of these columns, historical customer numbers from each power distributor's Rule 005 filings over the same sample period are displayed, and then summed to yield the total customers in the industry. Due to reporting differences between companies, lighting customers are excluded. Further to the right, historical gas customer numbers are shown for individual distributors and for the gas distribution industry.

[83] This calculation was made solely for the purpose of measuring input price and productivity *trends* and does not prescribe appropriate rate of return *levels* for utilities in Alberta.

Table A.1
Alberta Electric and Gas Customer Trends

Year	Alberta Population Trend[1] (*Historical Plus Projections*)			Electric Customers by Utility[2] (*Historical*)				Total Electric Customers[3] (*Historical Plus Projections*)						Gas Customers by Utility[4] (*Historical*)		Total Gas Customers[3] (*Historical Plus Projections*)					
	Low Projection	Medium Projection	High Projection	FortisAlberta	EDTI	Enmax	ATCO Electric	Low Projection	Growth Rate	Medium Projection	Growth Rate	High Projection	Growth Rate	ATCO Gas	AltaGas	Low Projection	Growth Rate	Medium Projection	Growth Rate	High Projection	Growth Rate
2004				396,538	294,799	378,624	182,068	1,252,029		1,252,029		1,252,029		914,347	60,416	974,763		974,763		974,763	
2005	2.54%	2.54%	2.54%	432,177	302,342	387,891	186,134	1,308,544	4.41%	1,308,544	4.41%	1,308,544	4.41%	939,598	61,783	1,001,381	2.69%	1,001,381	2.69%	1,001,381	2.69%
2006	2.96%	2.96%	2.96%	445,375	311,516	399,175	191,132	1,347,198	2.91%	1,347,198	2.91%	1,347,198	2.91%	969,877	63,792	1,033,669	3.17%	1,033,669	3.17%	1,033,669	3.17%
2007	2.67%	2.67%	2.67%	462,392	319,893	407,849	197,354	1,387,488	2.95%	1,387,488	2.95%	1,387,488	2.95%	1,001,846	66,395	1,068,241	3.29%	1,068,241	3.29%	1,068,241	3.29%
2008	2.30%	2.30%	2.30%	478,578	326,269	417,313	202,824	1,424,984	2.67%	1,424,984	2.67%	1,424,984	2.67%	1,022,167	68,525	1,090,692	2.08%	1,090,692	2.08%	1,090,692	2.08%
2009	2.29%	2.29%	2.29%	490,184	330,699	423,588	206,980	1,451,451	1.84%	1,451,451	1.84%	1,451,451	1.84%	1,037,412	69,561	1,106,973	1.48%	1,106,973	1.48%	1,106,973	1.48%
2010	1.44%	1.44%	1.44%	500,928	336,036	431,131	210,630	1,478,725	1.86%	1,478,725	1.86%	1,478,725	1.86%	1,057,369	71,005	1,128,374	1.91%	1,128,374	1.91%	1,128,374	1.91%
2011	1.53%	1.53%	1.53%	510,352	341,607	437,135	213,022	1,502,116	1.57%	1,502,116	1.57%	1,502,116	1.57%	1,074,261	72,038	1,146,299	1.58%	1,146,299	1.58%	1,146,299	1.58%
2012	2.56%	2.56%	2.56%	519,367	348,619	444,616	215,964	1,528,566	1.75%	1,528,566	1.75%	1,528,566	1.75%	1,095,586	73,674	1,169,260	1.98%	1,169,260	1.98%	1,169,260	1.98%
2013	3.00%	3.00%	3.00%	529,532	357,483	454,136	219,951	1,561,102	2.11%	1,561,102	2.11%	1,561,102	2.11%	1,118,566	75,030	1,193,596	2.06%	1,193,596	2.06%	1,193,596	2.06%
2014	2.82%	2.82%	2.82%	540,875	366,761	463,669	223,259	1,594,564	2.12%	1,594,564	2.12%	1,594,564	2.12%	1,143,624	76,638	1,220,262	2.21%	1,220,262	2.21%	1,220,262	2.21%
2015	1.45%	1.94%	2.57%					1,618,035	1.46%	1,625,949	1.95%	1,636,151	2.57%			1,236,095	1.29%	1,242,140	1.78%	1,249,935	2.40%
2016	1.33%	1.64%	2.06%					1,639,838	1.34%	1,652,999	1.65%	1,670,347	2.07%			1,250,597	1.17%	1,260,634	1.48%	1,273,864	1.90%
2017	1.29%	1.64%	2.13%					1,661,176	1.29%	1,680,510	1.65%	1,706,352	2.13%			1,264,692	1.12%	1,279,411	1.48%	1,299,085	1.96%
2018	1.36%	1.80%	2.39%					1,684,056	1.37%	1,711,135	1.81%	1,747,723	2.40%			1,279,907	1.20%	1,300,487	1.63%	1,328,295	2.22%
2019	1.37%	1.88%	2.58%					1,707,426	1.38%	1,743,691	1.88%	1,793,558	2.59%			1,295,437	1.21%	1,322,952	1.71%	1,360,786	2.42%
2020	1.32%	1.83%	2.51%					1,730,202	1.33%	1,776,066	1.84%	1,839,276	2.52%			1,310,461	1.15%	1,345,198	1.67%	1,393,074	2.35%
2021	1.25%	1.74%	2.37%					1,752,128	1.26%	1,807,286	1.74%	1,883,503	2.38%			1,324,786	1.09%	1,366,491	1.57%	1,424,119	2.20%
2022	1.21%	1.67%	2.28%					1,773,569	1.22%	1,837,834	1.68%	1,927,058	2.29%			1,338,692	1.04%	1,387,199	1.50%	1,454,545	2.11%
2023	1.19%	1.65%	2.26%					1,794,906	1.20%	1,868,505	1.66%	1,971,178	2.26%			1,352,468	1.02%	1,407,924	1.48%	1,485,289	2.09%
Average annual growth rates:																					
2005-2014	**2.41%**	**2.41%**	**2.41%**						**2.42%**		**2.42%**		**2.42%**				**2.25%**		**2.25%**		**2.25%**
2006-2014	**2.40%**	**2.40%**	**2.40%**						**2.20%**		**2.20%**		**2.20%**				**2.20%**		**2.20%**		**2.20%**
2018-2023	**1.28%**	**1.76%**	**2.40%**						**1.29%**		**1.77%**		**2.40%**				**1.12%**		**1.60%**		**2.23%**

Notes:

[1] Population growth rates are based on the low-growth, medium-growth, and high-growth scenarios for Alberta, released by the Alberta Treasury Board and Finance in July 2015 (retrieved in March 2016 from: http://finance.alberta.ca/aboutalberta/population-projections/index.html).

[2] Electric customers are the total customers for each utility, excluding lighting (i.e., exterior, space, street, traffic, lane, and security lighting customers). Electric customer data are drawn from each utility's Rule 005 filings, and represent average customers. ATCO Electric did not report the number of transmission direct connect customers for 2004, so these are not included in the total for that year (in 2005 there were 28 such customers).

[3] The 2015-2023 forecasts represent the average historical customer growth rate adjusted for the difference between the forecast population growth rate for each year and the average historical population growth rate. In other words, *trend* Customer$_{forecast,\ year\ i}$ = *trend* Customer$_{historical,\ average}$ + *trend* Population$_{forecast,\ year\ i}$ - *trend* Population$_{historical,\ average}$

[4] Gas customer data are drawn from each utility's Rule 005 filings, and represent end-of-year customers. The 2004 and 2005 numbers for AltaGas are estimates, since the Rule 005 filings prior to 2007 report average numbers. Thus, the end-of-year values for 2004 and 2005 for AltaGas are estimated by taking averages of the reported numbers (e.g., the 2005 end-of-year value shown is the average of the reported 2005 and 2006 average numbers). Since the 2006 end-of-year value is reported on AltaGas' 2007 filing, it is not estimated.

Growth in the *total* number of customers in each industry is forecasted. To produce these forecasts, the average annual historical customer growth is first computed for each industry. This trend is then adjusted by the difference between the projected trend in Alberta's population for a given year and the average annual historical population trend. This produces a forecast that reflects the Alberta Treasury Board and Finance population growth projections, while allowing for differences between the growth rates of industry customers and the population as a whole. For the 2018-23 period, this methodology produces a forecast of 1.77% annual electric customer growth and 1.60% gas customer growth. The customer growth trends used to inform our productivity analysis are based on the medium growth projection.

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Statistical Research for Public Service Company of Colorado's Multiyear Rate Plan

Pacific Economics Group Research, LLC

STATISTICAL RESEARCH FOR PUBLIC SERVICE COMPANY OF COLORADO'S MULTIYEAR RATE PLAN

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1. Introduction and Summary

1.1 Introduction

Public Service Company of Colorado ("Public Service" or "the Company"), a wholly owned regulated utility subsidiary of Xcel Energy, is proposing a multiyear rate plan ("MYP") for its gas utility services. The plan would set rates in the three year 2018-20 period. The Company has used a hybrid methodology for establishing revenue requirements in these years that includes some forecasts.

Forward test years ("FTYs") are permitted in Colorado, but FTY evidence is viewed with caution by stakeholders. In past proceedings, some have noted the difficulty of verifying the reasonableness of FTY projections. Stakeholders have also touted the ability of historical test years ("HTYs") to bolster utility performance incentives.

The personnel of Pacific Economics Group Research LLC ("PEG") have extensive experience in the fields of utility cost research and MYP design. Testimony quality benchmarking and productivity studies are specialties. We pioneered the use of rigorous statistical cost research in North American energy utility regulation. Mark Newton Lowry, company president and senior author of this report, has testified in numerous proceedings on benchmarking and the use of index research in MYP design.

Public Service has retained PEG to conduct three empirical research tasks that are relevant to its MYP filing. One is to benchmark the Company's proposed revenue requirements in each plan year. Another is to use index research to develop an escalator for the component of the Company's proposed revenue requirement which compensates it for non-gas O&M expenses. A third task is to use statistics to consider whether historical test years improve gas utility cost performance.

Following a brief summary of the work in Section 1.2 immediately below, Section 2 provides an introduction to statistical benchmarking. Section 3 discusses our benchmarking work for Public Service. Section 4 considers the cost impact of historical test years, while Section 5 discusses our index research. Some technical details of the research are presented in the Appendix.

1.2 Summary of Research

We addressed the reasonableness of the Company's proposed revenue requirements using statistical benchmarking. We benchmarked the Company's proposed revenue for non-gas operation and maintenance ("O&M") expenses and total non-gas cost. Some kinds of cost were excluded from the study because they were unusually volatile, difficult to benchmark, substantially beyond utility control, and/or scheduled for separate tracking under the proposed plan. The non-gas O&M expenses we benchmarked were the total expenses less those expenses for gas supply, gas transmission by others, compressor fuel, customer service and information, pensions and benefits, uncollectible accounts, and franchise fees. The total non-gas cost that we benchmarked were these same non-gas O&M expenses plus three components of capital cost: amortization, depreciation, and return on net plant value.

Two well-established benchmarking methods were employed in the study: econometric modeling and unit cost indexing. Guided by economic theory, we developed models of the impact various business conditions have on the non-gas O&M expenses and total non-gas cost of local gas distribution companies ("LDCs"). The parameters of each model, which measure the impact of the business conditions on cost, were estimated econometrically using historical data on LDC operations. Models fitted with econometric parameter estimates and the business conditions Public Service expects to face during the three MYP years generated revenue requirement benchmarks. We also used a simpler unit cost benchmarking method.

The benchmarking work employed a sample of good quality data for 33 LDCs in the United States. These are companies for which good capital cost data needed for the total non-gas cost appraisal are available. The sample includes most U.S. LDCs that, like Public Service, serve more than one million customers.[1] Most cost data used in the study were drawn from LDC reports to state utility commissions. These reports typically use the Federal Energy Regulatory Commission ("FERC") Form 2 as a template. A Uniform System of Accounts has been established for this form.

The sample period for the econometric work was 1998 to 2015. The sample is large and varied enough to permit development of sophisticated cost models in which several drivers of LDC

[1] Data were problematic for several large LDCs.

cost are identified. Estimates of model parameters were plausible and almost all were statistically significant.

The revenue requirement for non-gas O&M expenses which Public Service proposes for the 2018-20 period were found to be about 31% below the benchmarks generated by our econometric model of non-gas O&M expenses on average. This score is commensurate with top quartile (specifically number 7 of 33) performance. The proposed revenue for total non-gas cost is about 22% below the benchmarks generated by our total non-gas cost model on average. This score is also commensurate with a top quartile (specifically number 7 of 33) performance.

As for the unit cost benchmarking, we compared the proposed unit revenue requirements of Public Service to the 2015 unit costs of seven sampled western LDCs. The unit non-gas O&M revenue proposed by Public Service was found to be 42% below the peer group norm. This score is commensurate with a top quartile (specifically number one of eight) performance. The total non-gas revenue proposed by Public Service was found to be 19% below the peer group norm. This score is commensurate with a number four of eight ranking, near the border between a first and second quartile performance. We conclude from our benchmarking work that the Company's proposed revenue requirements for the three MYP years reflect good levels of operating performance.

To test the effect that using historical test years in rate cases has on cost management, we developed an econometric model of the growth in non-gas O&M expenses. We found no tendency for O&M cost to grow more slowly for utilities that operate in historical test year jurisdictions. We reached similar conclusions in previous studies we filed on this topic in Public Service proceedings.

Indexes have been used in many approved MYPs to escalate utility rates or revenue requirements. In some plans, these indexes operate in real time, while in others they are used to establish rate or revenue escalation before the plan begins. The index formula we developed for the non-gas O&M revenue of Public Service is

$$\textit{growth } Revenue_{PSCO}^{O\&M} = \textit{growth Input Prices} - X + \textit{growth Customers}_{PSCO}.$$

Here X is the 0.57% long run trend in the O&M productivity growth target of our sampled LDCs. Using this trend and forecasts of O&M input price inflation and the Company's customer growth, the indicated escalation in O&M revenue is 2.99%. The difference between 2.99% and the non-gas O&M revenue growth that the Company proposes can be deemed a stretch factor.

The Company forecasts growth in the non-gas O&M revenue requirement that we benchmark to average 0.87% during the MYP period. The difference between the forecasted growth in our O&M revenue escalator and the growth which the Company proposes is an estimate of the stretch factor that is implicit in their proposal. This stretch factor is 2.12%. Approved stretch factors in indexed rate and revenue caps of North American energy utilities typically range between 0 and 0.60%.

2. An Introduction to Benchmarking

In this Section of the report we provide a non-technical introduction to cost benchmarking. The two benchmarking methods used in the study are explained. Details of our benchmarking work for Public Service are discussed in Section 3 and the Appendix.

2.1 What is Benchmarking?

The word benchmark originally comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as

> A surveyors mark, cut in some durable material, as a rock, wall, gate pillar, face of a building, etc. to indicate the starting, closing, ending or any suitable intermediate point in a line of levels for the determination of altitudes over the face of a country.

The term has subsequently been used more generally to indicate something that can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise involves one or more activity measures. These are sometimes called performance metrics or indicators. The value of each indicator achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of Public Service and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\textit{Cost Performance} = \textit{Cost}^{PSCo}/\textit{Cost}^{Benchmark}.$$

Benchmarks are often developed statistically using data on the operations of agents engaged in the same activity. In utility cost benchmarking, data on the costs of utilities can be used to establish benchmarks. Various performance standards can be used in benchmarking, and these often reflect statistical concepts. One sensible standard for utilities is the average performance of the utilities in the sample. An alternative standard is the performance that would define the margin of the top quartile of performers. An approach to benchmarking that uses statistical methods is called statistical benchmarking.

These concepts are usefully illustrated by the process for choosing athletes for the Pro Football Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Quarterbacks, for example, are evaluated using multiple performance indicators that include touchdowns, passing yardage, and interceptions. Values for these metrics which Hall of Fame members like Denver Broncos star John Elway have achieved are far superior to league norms.

2.2 External Business Conditions

When appraising the relative performance of two sprinters, comparing their times in the 100-meter dash when one runs uphill and the other runs on a level surface isn't very informative since runner speed is influenced by the slope of the surface. In comparing costs that utilities incur, it is similarly recognized that differences in their costs depend in part on differences in external business conditions that they face. These conditions are sometimes called cost "drivers." The cost performance of a company depends on the cost it achieves given the business conditions it faces. Benchmarks must therefore reflect external business conditions.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to business conditions in its service territory. When the focus of benchmarking is total non-gas cost, theory reveals that the relevant business conditions include the prices of capital and O&M inputs and the operating scale of the company. Miscellaneous other business conditions may also drive cost. When the focus of benchmarking is non-gas O&M expenses, prices of non-gas O&M inputs and the quantity of capital used by the company matter.

The existence of capital input variables in O&M cost functions means that appraising the efficiency of a utility in using O&M inputs requires consideration of the kinds and quantities of capital inputs it uses. This result is important for several reasons. It is generally more costly to operate and maintain capacity the more of it there is. A utility that has newer facilities and services will spend less on maintenance than a distributor struggling with older facilities nearing replacement age.

Regardless of the particular category of cost benchmarked, economic theory allows for the existence of multiple scale variables in cost functions. The cost of a distributor depends on the number of customers it serves (as it provides distribution and customer care services) as well as on its delivery volume. Public Service provides diverse gas services (e.g., transmission and distribution) that in other jurisdictions are provided by different companies.

2.3 Benchmarking Methods

In this Section we discuss the two benchmarking methods we used in this study for Public Service. We begin with the econometric method to establish a better context for the discussion of the indexing method.

2.3.1 Econometric Modeling

In Section 2.2, we noted that comparing results of a 100-meter sprinter racing uphill to a runner racing on a level course doesn't tell us much about the relative performance of the athletes. Statistics can aid appraisal of their performances. For example, we could develop a mathematical model in which time in the 100-meter dash is a function of conditions like wind speed and gradient. The parameters corresponding to each condition would quantify their typical impact on run times. We could then use samples of times turned in by runners under varying conditions to estimate model parameters. The resultant "run-time" model could then be used to predict the typical performance of runners given the track conditions they faced.

The relationship between the cost of utilities and the business conditions they face (sometimes called the "structure" of cost) can also be estimated statistically. A branch of statistics called econometrics has developed procedures for estimating economic model parameters using historical data.[2] Parameters of a utility cost function can be estimated using historical data on costs incurred by a group of utilities and business conditions they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a "cross section" consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

Basic Assumptions

Econometric research involves certain critical assumptions. One is that the value of an economic variable (called the dependent or left-hand side variable) is a function of certain other variables (called explanatory or right-hand side variables) and an error term. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced

[2] Estimation of model parameters is sometimes called regression.

by the value of the dependent variable. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables.

The error term in an econometric cost model is the difference between actual cost and the cost predicted by the model. This term is a formal acknowledgement of the fact that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities. Reasons for errors include mismeasurement of cost and external business conditions, exclusion from the model of relevant business conditions, and failure of the model to capture the true form of the functional relationship. It is customary to assume that error terms in econometric models are random variables drawn from probability distributions with measurable parameters.

Statistical theory is useful for appraising the importance of explanatory variables in cost models. Tests can be constructed for the hypothesis that the parameter for an included business condition equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

Cost Predictions and Performance Appraisals

A cost function fitted with econometric parameter estimates is called an econometric cost model. We can use such models to predict a company's costs given local values for the business condition variables.[3] These predictions are econometric benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. Cost predictions can be made for historical or future years. Predictions of cost

[3] Suppose, for example, that we wish to benchmark the cost of a hypothetical gas utility called Western Gas. We might then predict the cost of Western in period t using the following simple model.

$$\hat{C}_{Western,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Western,t} + \hat{a}_2 \cdot V_{Western,t}.$$

Here $\hat{C}_{Western,t}$ denotes the predicted cost of the company, $N_{Western,t}$ is the number of customers it serves, and $V_{Western,t}$ is its delivery volume. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula like

$$Performance = ln\left(C_{Western,t} \big/ \hat{C}_{Western,t} \right),$$

where ln is the natural logarithm of the ratio in the parentheses.

in future years can be used to benchmark forecasts or proposed revenue requirements for these costs.

Accuracy of Benchmarking Results

Statistical theory provides useful guidance regarding the accuracy of econometric benchmarks as predictors of the true benchmark. One important result is that a model can yield biased predictions of the true benchmark if relevant business condition variables are excluded from the model. It is therefore desirable to consider in model development numerous business conditions which are believed to be relevant and for which good data are available at reasonable cost.

Even when the predictions of an econometric model are unbiased they can be imprecise, yielding benchmarks that are too high for some companies and too low for others. Statistical theory suggests that the predictions will be more precise to the extent that

- the model successfully explains the variation in the historical cost data used in model development;
- the size of the sample used in model estimation is large;
- the number of cost-driver variables included in the model is small relative to the sample size;
- business conditions of sampled utilities are varied; and
- business conditions of the subject utility are similar to those of the typical firm in the sample.

These results suggest that econometric cost benchmarking will be more accurate to the extent that it is based on a large sample of good operating data from companies with diverse operating conditions. It follows that it will generally be preferable to use *panel* data in the research, encompassing information from multiple utilities over time, when these are available.

2.3.2 Benchmarking Indexes

In their internal reviews of operating performance utilities tend to employ index approaches to benchmarking rather than the econometric approach just described. Benchmarking indexes are also used occasionally in regulatory submissions. We begin our discussion with a review of index basics and then consider unit cost indexes.

Index Basics

An index is defined in one dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)."[4] In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to the corresponding values for a sample of utilities. The companies for which sample data have been drawn are sometimes called a peer group.

We have noted that a simple comparison of the costs of utilities reveals little about their cost performances to the extent that there are large differences in the cost drivers they face. In index-based benchmarking, it is therefore common to use as cost metrics the ratios of their cost to one or more important cost drivers. The operating scale of utilities in a peer group is typically the greatest source of difference in their cost. It makes sense then to compare ratios of cost to operating scale. Such a ratio is sometimes described as the cost per unit of operating scale or unit cost. In comparing the unit cost of a utility to the average for a peer group, we introduce an automatic control for differences between the companies in their operating scale. This permits us to include companies with more varied operating scales in the peer group.

A unit cost index is the ratio of a cost index to a scale index.

$$\textit{Unit Cost} = \textit{Cost}/\textit{Scale}. \qquad [1]$$

Each index compares the value of the metric to the average for a peer group.[5] The scale index can be multidimensional if it is desirable to measure operating scale using multiple scale variables.

Unit cost indexes do not control for differences in the other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility.

[4] *Webster's Third New International Dictionary of the English Language Unabridged*, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

[5] A unit cost index for Western Gas, for instance, would have the general form

$$\textit{Unit Cost}_t^{\textit{Western}} = \frac{\textit{Cost}_t^{\textit{Western}} / \textit{Cost}_t^{\textit{Peers}}}{\textit{Scale}_t^{\textit{Western}} / \textit{Scale}_t^{\textit{Peers}}}.$$

One sensible upgrade to unit cost indexes is to adjust them for differences in the input prices utilities face. The formula for real (inflation-adjusted) unit cost is

$$Unit\ Cost^{Real} = \frac{Cost\,/\ Input\ Prices}{Scale}. \qquad [2]$$

It can be shown that cost is the product of properly-designed input price and quantity indexes:

$$Cost = Input\ Prices \bullet Input\ Quantities. \qquad [3]$$

Relations [2] and [3] imply that

$$Unit\ Cost^{Real} = \frac{Input\ Quantities}{Scale} = 1/Productivity. \qquad [4]$$

Thus, a real unit cost index will yield the same benchmarking results as a productivity index. We discuss productivity indexes further in Section 5.2 below.

Multidimensional Scale Indexes

Indexes can be designed to summarize results of multiple comparisons. Such summaries involve averages of the comparisons. Consumer price indexes are familiar examples. These commonly summarize inflation (year-to-year comparisons) in prices of a market basket of goods and services. The weight for the price of each product is its share of the value of all of the products in the basket. If households typically spend $300 a week on food and $30 on coffee, for example, a 3% increase in the price of food would have a much bigger impact on the CPI than the same increase in the price of coffee.

To better appreciate advantages of multi-dimensional indexes in cost benchmarking, recall from our discussion above that the operating scale of a utility is sometimes most accurately measured using several scale variables. These variables can have different cost impacts even if all are worth considering. We can construct indexes of operating scale that take weighted averages of scale comparisons. In a cost-benchmarking application, it makes sense for the weights of such a scale index to reflect the relative importance of the scale variables as cost drivers.

The cost impact of a scale variable is conventionally measured by its cost “elasticity.” The elasticity of cost with respect to the number of customers served, for instance, is the percentage change in cost that results from a 1% change in the number. It is straightforward to estimate elasticities like these using econometric estimates of cost model parameters. The weight for each variable in the scale index can then be its share in the sum of the estimated cost elasticities of the model’s scale variables.

3. EMPIRICAL RESEARCH FOR PUBLIC SERVICE

3.1 Data

Diverse data sources were used in our LDC cost research. Data for some years before the start of the econometric sample period, which we use to calculate capital cost, are drawn from Uniform Statistical Reports that gas utilities filed with the American Gas Association ("AGA").[6] The number of LDCs that file these reports and release them to the public has always been limited and has declined over the years.

The development of a good sample has therefore required us to obtain cost and quantity data for later years from other sources including, most notably, annual reports that LDCs file with state regulators. These reports are fairly standardized since they often use the Form 2 that interstate gas pipeline companies file with the FERC. The FERC has established a Uniform System of Accounts for these data. Data on the common plant of combined gas and electric utilities were obtained from their FERC Form 1 reports. The chief source for our data on the operating scale of LDCs was Form EIA 176. Data from all of these public sources are compiled by commercial vendors. We obtained our data for the sample years of this study from SNL Financial.[7]

Input price data used in the study were drawn from Whitman, Requardt & Associates, the Regulatory Research Associates unit of SNL Financial, RSMeans, the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor, the Federal Reserve Bank, and Global Insight. Forecasts of inflation, between 2016 and 2020, in construction costs and prices of O&M inputs used by LDCs were obtained from Global Insight. Data on miles of transmission and distribution line owned by LDCs, and the composition of these lines were obtained from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation.

Forecast data for the cost and business conditions of Public Service were provided by the Company. These data are consistent with the Company's rate case filing. Our principal source of data on test years used in rate cases was Regulatory Research Associates.

[6] Data from these reports are aggregated and published annually by the Association in its *Gas Facts* publication.

[7] Where AGA and SNL data were insufficient, we used data from other sources.

Our benchmark research was based on operating data for 33 LDCs. This is a sample for which quality data are available for capital cost as well as O&M expenses. The sample includes data from more than 60% of the LDCs that, like Public Service, serve more than one million customers.[8] Some of the sampled LDCs in our research also provide gas transmission and/or storage services but all were involved more extensively in gas distribution.

The sampled companies are listed in Table 1. The table identifies the seven utilities in the western peer group whose data were used in the unit cost comparisons. These utilities are similar to Public Service in operating generally younger systems. Several are quite large, serve large western metropolitan areas, and/or have sizable transmission and storage operations. The sample period for the econometric benchmarking work was 1998-2015. The sample period for the research on test year incentives was 1999-2015.

The resultant data set for econometric model development has 594 observations. This sample is large and varied enough to permit identification of numerous LDC cost drivers and reasonably accurate estimation of their likely cost impact. The data set for the cost growth research had 561 observations.

3.2 Definition of Variables

3.2.1 Cost

Cost data played a key role in our research. The costs addressed in the benchmarking work were non-gas O&M expenses and capital costs. The non-gas O&M expenses considered were total gas utility O&M expenses less all reported expenses for gas production and purchases, gas transmission by others, compressor station fuel, customer service and information, employee pensions and benefits, uncollectible accounts, and franchise fees. The capital costs considered in the study were amortization and depreciation expenses and the pro forma return on net plant value. Taxes were excluded.

[8] Data for several of the larger LDCs (e.g., Southwest Gas) were too problematic to include in the study.

Table 1

Sample of LDCs Used in Empirical Research

Alabama Gas	*Pacific Gas and Electric*
Baltimore Gas & Electric	PECO Energy
Boston Gas	Peoples Gas Light and Coke
Brooklyn Union Gas	People's Natural Gas
Cascade Natural Gas	Public Service Electric and Gas
Central Hudson Gas & Electric	Public Service of Colorado
Connecticut Natural Gas	Public Service of North Carolina
Consolidated Edison of New York	*Puget Sound Energy*
East Ohio Gas	*Questar Gas*
Louisville Gas and Electric	Rochester Gas and Electric
Madison Gas and Electric	*San Diego Gas & Electric*
New Jersey Natural Gas	*Southern California Gas*
Niagara Mohawk Power	Southern Connecticut Gas
North Shore Gas	Washington Gas Light
Northern Illinois Gas	Wisconsin Gas
Northwest Natural Gas	Wisconsin Power and Light
Orange and Rockland Utilities	

Sample Size = 33 LDCs
Western Peers in Italics

We routinely exclude pension and benefit expenses from our cost benchmarking work since they will be separately tracked in the proposed MYP, vary with accounting practices, and are sensitive to volatile business conditions, such as equity prices, that are largely beyond utility control. Expenses for transmission by others were excluded because they will be tracked and the terms of transmission services provided by others are largely beyond company control. Customer service and information expenses were excluded because they vary greatly with the extent of a company's demand side management ("DSM") programs, the scale of DSM programs is difficult to measure, and DSM expenses (which would be tracked) are not typically itemized for easy removal. Taxes and franchise fees (some of which would be tracked in the MYP) also vary greatly between LDCs and are largely beyond their control.

Capital cost is the product of a capital quantity index and a capital service price index. The capital price index measures capital cost per unit of plant owned. One advantage of this approach is that a capital price is needed in the total cost function. Another is that it facilitates the benchmarking of capital cost using data for utilities with different plant vintages and depreciation policies. To accomplish this, we apply to all utilities in the sample a standard method for depreciating gross plant additions. Data are needed for many years of additions, and the number of companies for which these data are available were limited.

Our approach yields an estimate of the capital cost of Public Service that differs somewhat from that filed in this proceeding. However, the specific approach used in this study is designed to be broadly consistent with the way capital cost is calculated by U.S. utilities in setting revenue requirements. Key aspects of this approach include straight line depreciation and book (historic) valuation of plant.

3.2.2 Output Measures

Two scale variables were identified in the econometric O&M cost research: the number of customers served and residential and commercial gas throughput. The number of customers and total retail throughput were the scale variables identified in the total econometric cost research. We expect cost to be higher the higher is a company's operating scale. The parameters of all of these variables should therefore have positive signs.

3.2.3 Input Prices

Cost theory also indicates that the prices paid for production inputs are relevant business condition variables. In the non-gas O&M cost research we used a summary O&M input price index.[9] In the total cost research we used a summary index that encompassed prices of capital as well as O&M inputs.

O&M

The O&M input price index was constructed by PEG Research from price subindexes for labor and materials and services. The growth rate of the summary O&M input price index is a weighted average of the price subindexes. The shares of salary and wage ("S&W") and material and service ("M&S") expenses in the included O&M expenses of the sampled LDCs were used as

[9] In estimating each cost model we divided cost by the appropriate summary input price index. This is commonly done in econometric cost research because it simplifies model estimation and enforces the relationship between cost and input prices that is predicted by economic theory.

weights. Many of the sampled LDCs did not itemize these expenses in their reports to state regulators. We accordingly used shares calculated from the data reported by the combined gas and electric utilities in the sample on their FERC Form 1 reports.

We developed the labor price index from BLS data. Occupational Employment Survey data for 2011 were used to construct average wage rates for the service territory of each sampled LDC. These were calculated as a weighted average of the survey pay levels for several job categories, using weights that correspond to the gas distribution sector of the U.S. economy. Values for other years were calculated by adjusting the level in 2011 for the estimated inflation in the regional salaries and wages of utility workers.[10] The estimated inflation was calculated from BLS employment cost indexes.

Summary indexes of prices for M&S inputs were calculated for each company from Global Insight price indexes for transmission, distribution, storage, customer account, and administrative and general ("A&G") O&M inputs. Using information provided by Global Insight, the price subindex for A&G inputs was adjusted to reflect our exclusion of pension and benefit expenses from the study. M&S prices were assumed to have a 25% local labor content and therefore to be a little higher in regions with higher labor prices. We used the 2011 labor price levelization just explained to achieve this.

Capital

Our formulas for the capital service prices are presented in Appendix Section 3. The capital costs reflected in these prices are amortization, depreciation, and the return on net plant value. Market construction costs and the rate of return on plant play key roles in the price formula.

The rate of return on plant is a 50/50 average of a bond yield and a rate of return on equity ("ROE"). For the bond yield we used the average annual yield on Baa bonds as calculated by Moody's Investor Service and reported by the Federal Reserve Bank. We used as the return on

[10] The growth rate of the labor price index was calculated for most years as the growth rate of the national employment cost index ("ECI") for the salaries and wages of the utility sector plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole.

equity the annual average of the effective allowed ROEs, for a large sample of LDCs, which were approved by their regulators. The ROE data were obtained from Regulatory Research Associates.

We calculated an index of market construction costs that was allowed to vary between the service territories of sampled LDCs in 2009 in proportion to the relative cost of local construction as measured by the total (material and installation) City Cost Indexes published in RSMeans.[11] The market construction cost index values for earlier years were determined for each company using the rates of inflation in the appropriate regional Handy Whitman construction and equipment cost index for total gas utility plant.[12]

3.2.4 Other Business Conditions

O&M Cost Model

Six other business condition variables are included in the O&M cost model. One is the number of customers who receive *electric* service from the utility. This variable is intended to capture the extent to which the company provides power distributor services. Such diversification will typically lower reported *gas* utility cost due, in part, to the realization of economies of scope. These economies occur when inputs are shared in the provision of multiple services. The extent of diversification is greater the greater is the number of electric customers. We would therefore expect the value of this variable's parameter to be negative.

Another business condition is the share of the total miles of distribution main that are not made of cast iron and bare steel. This variable is calculated from the PHMSA line mile data. Cast iron and bare steel mains were common in gas system construction in the early days of the industry. They are still extensively used in older distribution systems located in the Midwest and the East. Greater use of cast iron and bare steel tends to raise O&M expenses. The sign for this variable's parameter should therefore be negative in the O&M model.

[11] RSMeans, *Heavy Construction Cost Data 2010*.

[12] Whitman, Requardt and Associates, *Handy-Whitman Index of Public Utility Construction Costs* (Baltimore Whitman, Requardt and Associates, various issues).

A third additional business condition variable is a binary variable that indicates whether a company serves a densely settled urban core. Since gas service is generally more costly in urban cores, we expect the parameter of this variable to have a positive sign.

A fourth additional business condition variable is a measure of system age. The measure of age we used in this study was the ratio of 2015 customers served to 1998 customers. This variable will have a larger value the younger is system age. We expect a younger system to involve lower O&M expenses. The parameter for this variable should therefore have a negative sign in the O&M model.

A fifth additional business condition is the share of gross gas utility plant value that is not for distribution facilities. This variable picks up the extent to which the utility is involved in gas transmission and storage activities. Such involvement should raise cost, so the expected sign of this variable is positive.

The O&M cost model also contains a trend variable. A trend variable permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Parameters for such variables typically have a negative sign in statistical cost research. The inclusion of this variable in the model means that our econometric benchmarks include an expectation of normal industry productivity growth.

Total Cost Model

Our total cost model contains the following business condition variables.

- Number of gas customers
- Total retail deliveries
- Share of residential and commercial deliveries in total retail deliveries
- Share of distribution miles not cast iron or bare steel
- Share of gas plant not distribution
- Urban core dummy
- System Age

Cost tends to be higher the higher is the share of residential and commercial deliveries in total retail deliveries. This is true chiefly due to the fact that residential and commercial customers contribute disproportionately to costs of customer care and peak day sendout. We expect the parameter for this variable to have a positive sign.

Cast iron and bare steel mains raise O&M expenses but lower capital cost due to their advanced depreciation. A younger system lowers O&M expenses, but may raise capital costs. The parameters for the cast-iron/bare-steel and system-age variables therefore cannot be predicted in the total cost model.

3.3 Parameter Estimates

Estimation results for the O&M and total cost models are reported in Tables 2 and 3, respectively. Because we used double log functional forms for these models, parameter estimates for the output variables are also estimates of the elasticities of the cost with respect to these variables.[13] The tables also report the values of the t statistic and p value which correspond to each parameter estimate. These are used to test the statistical significance of the individual parameter estimates.

In this study we employed critical values appropriate for a 95% confidence level in a large sample. The critical value of the t statistic corresponding to this confidence level is about 1.645 using a one-tailed test.[14] A parameter estimate with a t statistic exceeding 1.645 is statistically significant at a confidence level of at least 95%.

[13] Functional forms are discussed further in Section A.1 of the Appendix.

[14] A one-tailed test is used when a particular sign is expected for a variable's parameter.

Table 2

Econometric Model of Gas Distribution O&M Cost

VARIABLE KEY

YN = Number of Gas Customers
YVRC = Total Retail Deliveries to Residential and Commercial Customers
NE = Number of Electric Customers
NCSBD = Percent of Pipes not Cast Iron or Bare Steel
UC = Urban Core Dummy Variable
YNGROWTH = Growth in Customers During Sample Period
PND = Percent of Plant that is not Distribution
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YN	0.714	24.413	0.000	**YNGROWTH**	-0.739	-7.008	0.000
YVRC	0.099	3.784	0.000	**PND**	0.087	6.643	0.000
NE	-0.095	-3.584	0.000	**UC**	0.144	4.455	0.000
NCSBD	-0.292	-5.579	0.000	**Trend**	0.000	0.264	0.792
				Constant	11.917	299.178	< 2e-16
			Rbar-Squared	0.929			
			Sample Period	1998-2015			
			Number of Observations	594			

Table 3

Econometric Model of Gas Distribution Total Cost

VARIABLE KEY

YN = Number of Gas Customers
YV = Total Retail Deliveries
RC = Share of Residential & Commercial in Total Retail Deliveries
NCSBD = Percent of Pipes not Cast Iron or Bare Steel
PND = Percent of Gas Plant not Distribution
UC = Urban Core Dummy Variable
YNGROWTH = Growth in Customers During Sample Period
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YN	0.756	37.129	0.000	**PND**	0.070	8.018	0.000
YV	0.056	2.666	0.008	**UC**	0.181	6.131	0.000
RC	0.067	3.496	0.001	**Trend**	-0.005	-4.364	0.000
NCSBD	-0.147	-2.995	0.003	Constant	12.765	440.861	0.000
YNGROWTH	0.160	2.028	0.043				
			Rbar-Squared	0.948			
			Sample Period	1998-2015			
			Number of Observations	594			

3.3.1 O&M Cost Model

Examining the results in Table 2, it can be seen that all but one of the key parameter estimates for the O&M cost model are statistically significant and plausible as to sign and magnitude. Cost was found to be higher the higher were the two output quantities. At the sample mean, a 1% increase in the number of customers raised cost by about 0.71%. 1% growth in residential and commercial deliveries raised cost by about 0.10%.

Estimates of the parameters of the other business conditions were also sensible.

- Cost was lower the greater were the number of electric customers served.
- Cost was lower the greater were the shares of distribution mains not made of cast iron or bare steel.
- Cost was lower the younger was system age.
- Cost was higher for LDCs serving urban cores.
- Cost was higher the more that non-distribution plant such as transmission and storage was owned
- Cost was seemingly unaffected on balance by technological change and other conditions not otherwise specified in the model.

Table 2 also reports the adjusted R^2 statistic for the model. This measures the ability of the model to explain variation in the sampled costs of distributors. Its value was 0.929, suggesting that the explanatory power of the model was high.

3.3.2 Total Cost Model

Results reported in Table 3 for total cost are also sensible. All of the key cost function parameter estimates were statistically significant. At the sample mean, a 1% increase in the number of customers raised cost by about 0.76%. A 1% increase in total throughput raised cost by about 0.06%.

The estimates of the parameters of the other business conditions were also sensible.

- Cost was higher the greater was the share of residential and commercial deliveries in total retail throughput.

- Cost was lower the greater was the percentage of distribution mains not made of cast iron or bare steel. [15]
- Cost was higher the more non-distribution plant such as transmission and storage that the LDC owned.
- Cost was higher for distributors that served a core urban area.
- Cost was higher the younger was system age.[16]
- Cost shifted downward over time by about 0.51% annually for reasons not otherwise explained in the model.

The 0.948 adjusted R^2 indicates that the explanatory value of the model was high.

3.4 Business Conditions of Public Service

Public Service is a gas and electric utility with a large gas distribution system and extensive involvement in gas transmission. Metropolitan Denver is the heart of its gas distribution service territory. Gas distribution service is also provided to other Front Range communities, and to San Luis Valley, central Colorado, and Western Slope communities.

The Company's gas transmission system was originally developed to carry gas from Colorado gas fields to local communities. It largely predates the boom years of the modern Denver economy.[17] Most gas that Public Service distributes in smaller communities across the state is carried to these communities in Company pipelines. The transmission system also makes gas deliveries to interstate pipeline companies and independent LDCs.

In totality, Public Service owns over 24,000 miles of gas T&D lines. About 10% of these are transmission lines. Public Service also owns and operates gas storage facilities. There are only a few hundred miles of bare steel lines on the network.

Table 4 compares average values of the business conditions in the models that Public Service is expected to face in 2018 to the mean values of all companies in the econometric sample in 2015. It can be seen that the forecasted total non-gas cost of Public Service is about 13% above

[15] Evidently, higher O&M expenses from mains made from these materials offset lower capital cost.

[16] Evidently, the higher capital cost of a younger system offset O&M savings.

[17] This system also carries gas brought into the state by interstate pipeline companies such as Colorado Interstate Gas.

Table 4

Comparison of Public Service's Business Conditions to Full Sample Norms, 2015

Business Condition	Units	Public Service Values, 2018 [A]	Sample Mean, 2015 [B]	2018 Public Service Values / Sample Mean
Total Non-Gas Cost (2015 Dollars)	Dollars	504,176,291	447,142,350	1.13
Non-Gas O&M Expenses (2015 Dollars)	Dollars	175,111,912	195,682,364	0.89
Number of Retail Customers	Count	1,395,157	945,297	1.48
Retail Deliveries	Dekatherms	246,519,801	176,793,870	1.39
Residential and Commercial Deliveries	Dekatherms	138,115,305	98,514,657	1.40
Price Index for O&M Inputs (2015 Dollars)	Index Number	1.004	1.000	1.00
Share of Residential & Commercial in Total Retail Deliveries	Ratio	0.560	0.622	0.90
Percent of Plant that is not Distribution	Ratio	0.337	0.174	1.94
Number of Electric Customers	Count	1,476,358	636,022	2.32
Share of Distribution Miles not Cast Iron or Unprotected Bare Steel	Ratio	0.999	0.884	1.13
Urban Core Dummy	Binary	1.000	0.788	1.27
Total Customer Growth Over the 1998-2015 Sample Period	Ratio	1.344	1.226	1.10

the sample mean. Forecasted non-gas O&M expenses are 0.89 times the mean. This cost is, in other words, about 11% below the mean.

The forecasted number of customers served is, meanwhile, 1.48 times the mean while the forecasted retail throughput is 1.39 times the mean and forecasted residential and commercial throughput is 1.40 times the mean. Input prices are very similar to sample norms.

The forecasted share of residential and commercial deliveries in total retail throughput is 0.90 times the mean. The forecasted number of electric customers is 2.32 times the mean. This reflects the fact that most sampled LDCs did not, like Public Service, provide electric service.

The share of distribution mileage not made of cast iron and bare steel is above the mean. The service territory has an urban core, like most in the sample. The growth in the number of customers during the sample period was 1.10 times the mean. While this suggests that the Company's system is relatively young, it may still have older facilities approaching replacement age.

3.5 Unit Cost

The O&M and total non-gas cost of LDCs were both found in our empirical research to involve multiple statistically significant scale variables. Unit cost comparisons are thus most accurately made using unit cost indexes with multidimensional scale indexes. Cost elasticities were noted in Section 2.3.2 to provide sensible weights for such comparisons in a cost benchmarking study.

Our econometric work on O&M expenses indicates that, at sample mean values of the business conditions, the elasticities of cost with respect to customers and throughput were 0.714 and 0.099 respectively. The corresponding elasticity shares are 88% for customers and 12% for throughput. Our econometric work on total cost found that the elasticities of cost with respect to customers, and throughput were 0.756 and 0.056 respectively. The corresponding elasticity shares are 93% and 7% respectively.

3.6 Benchmarking Results

3.6.1 Econometric Models

Table 5 shows results of our benchmarking using the econometric models. The Company's proposed non-gas O&M revenue requirements during the 2018-20 period were found to be about 31% below the projection of our O&M cost benchmarking model on average. This score is commensurate with a top quartile (specifically seventh of thirty-three) ranking. The Company's forecasted total cost was found to be about 22% below the cost projected by our total cost benchmarking model on average during these years. This score is commensurate with a top quartile (specifically seventh of thirty-three) ranking. The Company's scores have been depressed in recent years by integrity management costs.

3.6.2 Unit Cost Indexes

Table 6 shows the results of benchmarking the proposed 2018-2020 revenue requirements using unit cost indexes. Comparisons are made to mean values for the western peer group in 2015. It can be seen that the Company's forecasted non-gas O&M unit cost was about 42% below the

Table 5

Summary of Econometric Benchmarking Results

[Actual - Predicted Cost (%)]

Year	O&M Expenses	Total Cost
1998	-23.9%	-36.6%
1999	-21.1%	-34.2%
2000	-28.7%	-38.2%
2001	-15.6%	-33.7%
2002	-26.2%	-37.7%
2003	-40.2%	-43.8%
2004	-50.7%	-46.3%
2005	-53.5%	-47.0%
2006	-52.7%	-48.0%
2007	-50.7%	-48.5%
2008	-50.6%	-50.2%
2009	-47.4%	-50.3%
2010	-44.0%	-48.0%
2011	-36.9%	-44.0%
2012	-25.8%	-38.7%
2013	-29.9%	-39.6%
2014	-32.4%	-34.4%
2015	-27.5%	-30.9%
2016	-19.7%	-25.5%
2017	*-26.7%*	*-23.9%*
2018	*-28.8%*	*-22.6%*
2019	*-31.3%*	*-22.3%*
2020	*-33.9%*	*-22.3%*
Average - 2018-2020	**-31.3%**	**-22.4%**

Notes: Italicized numbers indicate forecast.
Formula for benchmark comparison is $\ln(Cost^{PSCO}/Cost^{Bench})$.

Table 6

How Public Service's 2018 Unit Cost Compares to 2015 Sample Norms

Non-Gas O&M Cost[1] (2015 dollars)

	Public Service 2018-2020 Average [A]	Western Peers 2015 [2] [B]	Comparing Results: Ratio [A/B]	Comparing Results: Percentage Difference [(A/B)-1]
Real O&M Cost	172,093,339	389,534,857	0.442	-55.8%
Number of Customers	1,410,600	1,963,616	0.718	-28.2%
Residential and Commercial Deliveries	138,619,592	124,831,243	1.110	11.0%
Dollars per Customer[3]	$ 122.0	$ 198.4	0.615	-38.5%
Dollars per R&C Delivery[3]	$ 1.24	$ 3.12	0.398	-60.2%
Summary Unit Cost Index	**0.577**	**1.00**	**0.577**	-42.3%

Total Non-Gas Cost[1] (2015 dollars)

	Public Service 2018-2020 Average [A]	Western Peers 2015 [2] [B]	Comparing Results: Ratio [A/B]	Comparing Results: Percentage Difference [(A/B)-1]
Real Cost (with standardized capital cost)	507,234,612	858,838,355	0.591	-40.9%
Total Dekatherms	256,882,122	311,019,786	0.826	-17.4%
Dollars per Customer[3]	$ 359.6	$ 437.4	0.822	-17.8%
Dollars per Dkth[3]	$ 1.97	$ 2.76	0.715	-28.5%
Summary Unit Cost Index	**0.814**	**1.00**	**0.814**	-18.6%

[1] Costs are expressed in 2015 dollars.

[2] The Western peers are Cascade Natural Gas, Northwest Natural Gas, Pacific Gas & Electric, Puget Sound Energy, Questar Gas, San Diego Gas & Electric, and Southern California Gas.

[3] Unit cost values for the Western peer group were the average of the individual company unit cost values.

sample mean on average over the three-year period. This score is commensurate with a top quartile (specifically first of eight ranking). The Company's forecasted non-gas *total* unit cost was about 19% below the sample mean. This score is near the edge between a first and second quartile despite a number four ranking. This is because the performance of the companies ranked two, three and four are separated by less than 2%.

4. Performance Impact of Test Years

To address the impact of test years on incentives for good cost management we developed an econometric model of the growth of real non-gas O&M expenses. One driver of real O&M cost growth was identified: growth in the volume of residential and commercial deliveries. We added to the model a binary variable with a value of one for companies that were subject to historical test years in all rate case filings that occurred in the 1999-2015 sample period. If this variable had a negative and statistically significant parameter estimate, it would suggest that historical test years tend to slow annual cost growth.

Results of the exercise can be found in Table 7. It can be seen that the parameter for residential and commercial deliveries had a positive and significant sign, meaning that growth in these deliveries tended to accelerate cost growth. The parameter estimate for the historical test year dummy was very close to zero and highly insignificant. We accordingly cannot reject the hypothesis that a historical test year had no effect on real non-gas cost growth. A similar conclusion was drawn on this subject with respect to gas and electric utilities in our previous studies for Public Service. The results square with our experience, gathered over many years of incentive regulation research, that the choice of a test year has little impact on cost performance incentives.

The explanatory power of this model was low. Cost growth fluctuated from year to year due to miscellaneous business conditions that are difficult to measure. The parameter estimates are nonetheless meaningful and shed light on the test year performance impact.

Table 7

Econometric Model of Gas Distribution O&M Cost Growth

VARIABLE KEY

RC = Growth in Residential and Commercial Deliveries
HTY = ~~Urban Core~~ Historical Test Year Dummy Variable
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
RC	0.172	3.534	0.000
HTY	0.004	0.323	0.747
Trend	0.002	1.785	0.075
Constant	-0.014	-1.178	0.239

Rbar-Squared	0.021
Sample Period	1999-2015
Number of Observations	561

5. DESIGNING AN ESCALATOR FOR O&M REVENUE

5.1 Revenue Cap Indexes

Index research provides the basis for revenue requirement escalators that can be used in multiyear rate plans. The following result of cost theory is a useful starting point:

growth Cost = growth Input Prices – growth Productivity + growth Scale. [5]

Cost growth (i.e., the growth rate of cost) is the difference between growth in input price and productivity indexes plus growth in operating scale. This result provides the rationale for a revenue requirement escalator of the following general form:

growth Revenue = growth Input Prices – X + growth Scale [6a]

where

X = trend Productivity + Stretch. [6b]

Here *X*, the "X factor," is calibrated to reflect a base productivity growth trend target. This is typically based on the average historical trend in productivity indexes of a utility peer group. A "stretch factor" is often added to the formula which slows revenue requirement growth in a manner that shares with customers financial benefits of any productivity growth in excess of the peer group norm which is expected during the MYP.

The growth trend of a productivity trend index is the difference between the trends in a scale index (*Scale*) and an input quantity index.

trend Productivity = trend Scale – trend Input Quantities. [7]

The trend in cost is the sum of the trends of appropriately-designed input price and quantity indexes.

trend Cost = trend Input Prices + trend Input Quantities. [8]

The input quantity trend can then be measured as the difference between the trends in cost and an input price index.

trend Inputs = trend Cost - trend Input Prices. [9]

For LDCs, the econometric research discussed in Section 3.3 shows that the number of customers served is a useful scale variable for a revenue cap index. Relations [6a] and [6b] can then be restated as:

$$\begin{aligned}
&\textit{growth Revenue} \\
&\quad = \textit{growth Input Prices} - [(\textit{trend Customers} - \textit{trend Input Quantities}) + \textit{Stretch}] \\
&\qquad\qquad + \textit{growth Customers} \\
&\quad = \textit{growth Input Prices} - (\textit{trend Productivity}^N + \textit{Stretch}) + \textit{growth Customers}. \qquad [10]
\end{aligned}$$

Here $Productivity^N$ is a productivity index that uses the number of customers to measure the growth in scale.

Rearranging the terms of [10] we can state this result alternatively as:

$$\begin{aligned}
&\textit{growth Revenue} - \textit{growth Customers} \\
&= \textit{growth }(\textit{Revenue /Customer}) = \textit{trend Input Prices} - (\textit{trend Productivity}^N + \textit{Stretch}). \qquad [11]
\end{aligned}$$

This provides the basis for the following alternative "revenue per customer index" formula:

$$\textit{growth Revenue/Customer} = \textit{growth Input Prices} - X + Y + Z \qquad [12a]$$

where

$$X = \textit{trend Productivity}^N + \textit{Stretch}. \qquad [12b]$$

This general approach to the design of revenue cap indexes is currently used in the MYPs of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Gaz Métro and Hydro-Quebec to develop plans for their distribution services featuring these formulas. Revenue per customer indexes were previously used by Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the United States and Canada respectively.

5.2 More on Productivity Indexes

The Basic Idea

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

The scope of a productivity index depends on the array of inputs considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. An O&M productivity index measures productivity in the use of O&M inputs.

$$\textit{trend Productivity}^{O\&M} = \textit{trend Scale} - \textit{trend Input Quantities}^{O\&M}. \qquad [13]$$

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

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse.[18] One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

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

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

Another driver of productivity growth is changes in the miscellaneous external business conditions, other than input price inflation and scale growth, which affect cost. A good example for a gas distributor is the share of distribution lines which are made of cast iron or bare steel. A

[18] For a seminal discussion of sources of productivity growth see Michael Denny, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., Productivity Measurement in Regulated Industries, (Academic Press, New York) pages 172-218.

reduction in the share of lines made of these materials will tend to accelerate O&M productivity growth since there is less maintenance.

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

5.3 O&M Productivity Trend of U.S. Gas Distributors

Index Construction

O&M productivity growth was calculated for each gas utility in our sample as the difference between the growth rates of scale and O&M input quantities. We used as a proxy for scale growth the growth in the total number of retail customers served. O&M input quantity growth was measured as the difference between growth in applicable non-gas O&M expenses and growth in the non-gas O&M input price index we used in the econometric work.

Sample Period

The full sample period for which productivity trends were calculated was 1999-2015. In other words, 1999 was the earliest year for growth rate calculations.

Productivity Results

Table 8 presents results of our O&M productivity research for our full 33-company sample. Over the full 1999-2015 sample period, the average annual growth rate in the O&M productivity of all sampled LDCs was about 0.57 percent. Growth in scale averaged 1.14 percent annually, while O&M input quantity growth averaged 0.57 percent. Over the more recent 2006-2015 sample period (i.e., the last ten years for which data are available), the average annual growth rate in the O&M productivity of all sampled LDCs was only -0.03 percent. Growth in scale slowed to average 0.78 percent annually, while O&M input growth increased to 0.81 percent. We chose 0.57% as our estimate of the long-term O&M productivity growth trend of U.S. gas distributors.

Table 8

O&M Productivity Results For Sampled Gas Distributors

(Growth Rates)[1]

Year	Scale	O&M Input Quantities	O&M Productivity
1998	NA	NA	NA
1999	2.12%	-0.82%	2.94%
2000	2.21%	3.83%	-1.62%
2001	1.56%	-6.37%	7.93%
2002	1.42%	-1.49%	2.91%
2003	1.41%	1.39%	0.02%
2004	1.13%	2.23%	-1.10%
2005	1.70%	2.76%	-1.07%
2006	1.52%	-4.90%	6.42%
2007	1.21%	2.55%	-1.33%
2008	0.49%	-1.16%	1.65%
2009	0.32%	4.43%	-4.11%
2010	0.49%	0.58%	-0.09%
2011	0.80%	0.27%	0.53%
2012	0.52%	-2.69%	3.21%
2013	0.80%	4.72%	-3.92%
2014	0.68%	3.31%	-2.63%
2015	1.02%	1.02%	-0.01%
Average Annual Growth Rate			
1999-2015	**1.14%**	**0.57%**	**0.57%**
2006-2015	**0.78%**	**0.81%**	**-0.03%**

[1]All growth rates are calculated logarthmically.

5.4 Index-Based Forecast of O&M Cost Growth

Table 9 presents a forecast of growth in the non-gas O&M revenue of Public Service based on formula [10].[19] From 2018 to 2020, the non-gas O&M input price index we used in the benchmarking work is forecasted to average 2.46% growth.[20] Public Service forecasts the number of its gas customers to average 1.11% annual growth. Given, additionally, a 0.57% non-gas O&M productivity trend, it can be seen that our O&M revenue escalator would average 2.99% annual growth.

Table 9

Forecasted Growth in O&M Revenue Cap Index

		Forecasted Growth 2018-2020
Input Price Growth	I	2.46%
Growth in Public Service Customers	Y	1.11%
Productivity Factor	X	0.57%
Growth in O&M	[I + Y - X]	2.99%

The difference between this growth pace and the pace by which the Company proposes to escalate its non-gas O&M revenue is an estimate of the stretch factor that is implicit in their proposal. The Company forecasts growth in the non-gas O&M expenses that we benchmark to average 0.87% during the MYP period. The implicit stretch factor is thus 2.12%. Approved stretch factors in indexed rate and revenue caps of North American energy utilities are typically much lower, ranging between 0 and 0.60%.

[19] No stretch factor is used in the Table 9 calculations since we are using the revenue cap index to calculate an implicit stretch factor.

[20] This forecast makes use of forecasts of price subindexes from Global Insight.

Appendix

This Appendix provides additional and more technical details of our empirical research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods, capital cost, unit cost indexes, and productivity calculations.

A.1 Form of the Econometric Cost Models

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot V_{h,t} \,. \qquad [A1]$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t} \,. \qquad [A2]$$

In the double log model the dependent variable and both business condition variables (customers and deliveries) have been logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the number of customers.

Elasticity estimates are informative and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, the elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive, and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\begin{aligned} \ln C_{h,t} = {} & a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ & + a_4 \cdot \ln V_{h,t} \cdot \ln V_{h,t} + a_5 \cdot \ln V_{h,t} \cdot \ln N_{h,t} \end{aligned} \,. \qquad [A3]$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms like $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to an output variable may, for example, be lower for a small utility than for a large utility.

Interaction terms like $\ln V_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in deliveries may depend on the number of customers in the service territory.

The translog form is an example of a “flexible” functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model’s cost prediction falls.

A.2 Econometric Model Estimation

A variety of estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares (“OLS”), is readily available in econometric software. Another class of procedures, called generalized least squares (“GLS”), is appropriate under assumptions of more complicated and realistic error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

In order to achieve a more efficient estimator, we corrected for autocorrelation and heteroskedasticity in the error terms. These are common phenomena in statistical cost research. The estimation procedure was developed by PEG using the widely-used R statistical software program.

Note, finally, that the model specification was determined using the data for all sampled companies, including Public Service. However, computation of model parameters and standard errors for the prediction required that the utility of interest be dropped from the sample when we estimated the coefficients in the predicting equation. This implies that the estimates used in developing the cost model will vary slightly from those in the model used for benchmarking.

A.3 Capital Cost

In this Section we explain the mathematics of our approach to calculating the capital cost and price. We first discuss our treatment of gas utility plant and then address our treatment of common plant.

A.3.1 Gas Utility Plant

Our formulas for gas utility plant are complex but reflect how capital cost is calculated in U.S. utility regulation. For each utility in each year t of the sample period we define the following terms.

ck_t	Total non-tax cost of capital
ck_t^{Return}	Return on net plant value
$ck_t^{Depreciation}$	Depreciation expenses
WKA_{t-s}	Market cost per unit of plant constructed in year t-s
VK_{t-s}^{add}	Gross value of plant installed in year t-s
a_{t-s}	Quantity of plant added in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$
xk_t	Total quantity of plant
xk_t^{t-s}	Quantity of plant in year t that remains from plant additions in year t-s
VK_t	Total (book) value of plant at the end of last year
N	Average service life of plant
r_t	Rate of return on net plant value
WKS_t	Price of capital service

The non-tax cost of capital is the sum of depreciation and the return on net plant value.

$$ck_t = ck_t^{Return} + ck_t^{Depreciation}$$

There is a certain return and depreciation associated with the value of any plant added in the current or prior year *t-s* which has not been fully depreciated. Assuming straight line depreciation and book valuation of utility plant, the non-tax cost of capital can then be expressed as

$$
\begin{aligned}
ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot r_t + \sum_{s=0}^{N-1} WKA_{t-s} \left(1/N\right) \cdot a_{t-s} \\
&= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s}\right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{\left(1/N\right) \cdot a_{t-s}}{xk_t}
\end{aligned} \qquad [A4]
$$

The second term in the formula is a standardized approach to the calculation of depreciation that frees us from reliance on the depreciation expenses reported by utilities.

The total quantity of capital used in each year t can be expressed as the sum of the quantities of each vintage of capital.

$$
xk_t = \sum_{s=0}^{N-1} xk_t^{t-s}.
$$

Under straight line depreciation we posit that in the interval $[N-1, 0]$,

$$
xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \qquad [A5]
$$

The capital quantity in year t is thus linked to current and past plant additions by the formula

$$
xk_t = \sum_{s=0}^{N-1} \frac{N-S}{N} a_{t-s} \ . \qquad [A6]
$$

The size of the addition in year t-s can be expressed as

$$
a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \qquad [A7]
$$

Equations [A4] and [A7] together imply that

$$
\begin{aligned}
ck_t &= xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \\
&= xk_t \cdot WKS_t
\end{aligned} \qquad [A8]
$$

Capital is the product of a price index and quantity index where the capital price index has a formula

$$
\begin{aligned}
WKS_t &= \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \\
&= \sum_{S=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \left(r_t + \frac{1}{N-s}\right)
\end{aligned} \qquad [A9]
$$

It can be seen that market construction costs and the rate of return on net plant value play key roles in the capital price formula. The first term in the formula pertains to the return on net plant value. The second term pertains to depreciation. Both terms depend on market construction costs in many recent years and not just on the costs in the current year. The importance of the value of the market construction cost index in each year depends on the share, in the total quantity of plant, of the plant remaining from additions made in that year.

The accuracy of our capital cost and service price indexes is greater the greater are the number of years for which we have plant addition data. In this study, we had available plant addition data for the 1984 to 2015 period. Reasonable assumptions were made about plant additions in prior years. Any inaccuracy in these assumptions is mitigated by the fact that plant additions from years before 1984 are substantially depreciated by the later years of the sample period.

A.3.2 Common Plant

Common plant is plant of combined gas and electric utilities like Public Service which is common to the provision of gas and electric service. Typical components of common plant include intangible assets, structures and improvements, office furniture and equipment, and communications equipment. The cost of common plant is much smaller than that of gas utility plant. We accordingly elected to measure this cost and the corresponding price by a simpler method.

For each combined gas and electric utility in the sample used for development of the total cost model, we first allocated to gas service a share of the reported net value of common plant equal to the share of gas plant in the total net value of the Company's gas and electric plant. The return on the net value of common plant was calculated as the product of our rate of return, discussed in Section 3.2.3 above, and the net value of common plant assigned to gas. Amortization and depreciation of common plant was calculated as net plant value times the amortization and depreciation rate on common plant for Public Service. The input price for common plant cost was the same as that calculated for transmission and distribution plant.

A.4 Unit Cost Indexes

Each summary unit cost index that we calculate for Public Service in an MYP year like 2018 is the ratio of a cost index to an output quantity index.

$$Unit\ Cost_{PSCO,2018} = \frac{Cost_{PSCO,2018}}{Scale_{PSCO,2018}} \qquad [A10]$$

The cost index is the ratio of the Company's forecasted 2018 cost, deflated to 2015 dollars, to the mean cost for the peer group in 2015. Each scale index compares the forecasted 2018 values for Public Service to the corresponding sample norms in 2015. Thus,

$$Unit\,Cost_{PSCO,2018} = \left(\frac{Cost_{PSCO,2018}}{\overline{Cost}_{2015}} \right) \Bigg/ \sum se_i * \frac{Y_{PSCO,i,2018}}{\overline{Y}_{i,2015}} \qquad [A11]$$

Here $Cost_{PSCO,2018}$ is the real revenue requirement projected for Public Service, $Y_{PSCO,i,2018}$ is the Company's forecasted quantity of output *i*, and $\overline{Cost}_{2015}$ and $\overline{Y}_{i,2015}$ are the corresponding 2015 peer group means. The denominator of this formula takes a weighted average of the scale variable comparisons. The weight for each scale variable *i* (se_i) is its share in the sum of the cost elasticity estimates from the corresponding econometric cost model. The percentage difference between the unit cost index of Public Service and the sample norm, which is reported in Table 6, is calculated as 100 * ($Unit\ Cost_{PSCO,t} - 1$).

A.5 Additional Details on O&M Productivity Trend Research

We calculated an O&M productivity index for each company in our sample. The annual growth rate in each company's productivity index is given by the formula:

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Customers_t}{Customers_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right)$$

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

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