Exhibit No. ___

WRITTEN EVIDENCE

OF

DR. TOBY BROWN
DR. PAUL R. CARPENTER

FOR
ALTAGAS UTILITIES INC
ATCO ELECTRIC
ATCO GAS
ENMAX POWER CORPORATION
FORTISALBERTA INC

Proceeding ID No. 20414

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I. INTRODUCTION

Q1. Who are the authors of this written evidence?

A1. Dr. Paul Carpenter and Dr. Toby Brown are co-authors of this written evidence. We are Principals of The Brattle Group, an economic consulting firm. Dr. Carpenter's office is at 44 Brattle Street, Cambridge, Massachusetts 02138 and Dr. Brown's office is at 201 Mission Street, Suite 2800, San Francisco, California 94105.

Q2. Please describe your qualifications.

A2. Dr. Paul Carpenter is an economist specializing in the fields of industrial organization, finance and energy and regulatory economics. He received a Ph.D. in Applied Economics and an M.S. in Management from the Massachusetts Institute of Technology, and a B.A. in Economics from Stanford University, and has been involved in research and consulting on the economics and regulation of the natural gas, oil and electric utility industries in North America and abroad for over thirty years. He has frequently testified before federal and state regulatory commissions, in federal court and before the U.S. Congress, on issues of pricing, competition and regulatory policy in these industries. Outside of North America, he has advised governments and regulatory bodies on the structure and performance of their natural gas markets and the pricing of gas transmission services. These assignments have included testimony before the U.K. Monopolies and Mergers Commission and the Australian Competition Tribunal, and advice to the governments of and regulators in, Greece, Ireland, the Netherlands, New Zealand and Australia. He has been extensively involved in the evaluation of the economics and regulation of the natural gas pipeline industry in North America. He has testified before the National Energy Board and several provincial regulatory bodies on the subject of business risk and its relationship to the cost of capital for natural gas pipelines and distributors. He testified before the Alberta Utilities Commission in the generic Performance Based Ratemaking proceeding. Further details of his educational and professional background, as well as a listing of publications, are provided in his resume appended to this evidence as Attachment 1.

Dr. Toby Brown specializes in the regulation and economics of the gas and electricity sectors. He has fifteen years of experience across the U.S., Canada, the UK and Australia, primarily consulting for pipelines, utilities, and regulators, together with four years at Ofgem, the energy regulator in Great Britain. He has particular expertise in the application of incentive-based regulation in the energy sector, and provided advice to the ATCO Utilities during the generic Performance Based Ratemaking proceeding before the Alberta Utilities Commission. Dr. Brown's project experience includes analysing business risk in pipeline rate cases, assessing the economic impacts of alternative regulatory frameworks and competitive structures in the energy sector, and advising on regulatory best practices based on experience in different jurisdictions worldwide. Dr. Brown also provides litigation support in a wide range of areas, including damages estimations, competition assessments, gas contract arbitrations, and utility and pipeline rate cases. He holds a D.Phil. in chemistry from the University of Oxford. Dr. Brown's resume is appended to this evidence as Attachment 2.

Q3. By whom have you been retained in this proceeding?

A3. The Brattle Group has been retained by AltaGas Utilities Inc., the ATCO Utilities (ATCO Electric and ATCO Gas), ENMAX Power Corporation, and FortisAlberta Inc.

Q4. What assignment were you given in this proceeding?

A4. We were asked to review the "issues list" published by the Alberta Utilities Commission (AUC) and to recommend how issues 1–3 on the AUC's list (rebasing, the "X-factor" and capital additions)[1] should be addressed in this proceeding and reflected in the next generation generic performance-based ratemaking (PBR) plans. We have been asked to base our recommendations on the industry's experience of

[1] We were not asked to address the fourth issue (calculation of returns for re-opener purposes). We do not address issue 1e (timing of Phase II proceedings) because this sub-issue concerns implementation rather than policy design.

PBR in Alberta and other jurisdictions, the AUC's PBR principles,[2] and ratemaking principles more generally.

Q5. How have you approached this assignment?

A5. This proceeding is concerned with the design of the next generation generic PBR plan for the Alberta gas and electric distribution utilities. We understand that the intention of the AUC is to address certain issues, such as rebasing, which were not addressed in the first generic PBR proceeding, and also to refine the design of the first generation generic PBR plans where it would be beneficial in light of the AUC's PBR principles. We have therefore approached our assignment in this proceeding in light of experience gained by the utilities, the AUC and interveners with the first generation generic PBR plans. In addition, where relevant, we bring to bear our knowledge of PBR plans in other jurisdictions. However, we recognize that it is difficult to consider the design of the various elements of a PBR plan in isolation without considering the plan as a whole. Caution is therefore needed when applying experience from other jurisdictions.

Q6. How have you structured your direct evidence?

A6. We have structured our evidence to follow the issues and sub-issues set out in the AUC's final issues list. In section II we address rebasing, in section III we address the X-factor, and in section IV we address capital additions. Within each section, we introduce our understanding of the principles relevant to the issue before going on to examine each of the sub-issues raised by the AUC. We then provide our recommendation as to how that issue should be addressed.

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[2] The AUC's PBR principles are quoted in Decision 2012-237, paragraph 28.

II. REBASING

A. Introduction to Rebasing

Q7. What issues are you addressing in this section of your evidence?

A7. The first issue on the AUC's list is "rebasing and the establishment of going-in rates". We are addressing issues 1a through 1d:

> *1(a) How should going-in rates be set for the next PBR term?*
> *1(b) Is it necessary to rebase prior to the next generation of PBR? What would rebasing involve?*
> *1(c) What are the arguments for and against inserting a year of cost-of-service regulation after the current PBR term and prior to the start of the next generation PBR plan? What other possible methods are available to rebase rates for the start of the second generation PBR plans? Describe the arguments for and against these alternative approaches in terms of reducing regulatory burden, minimizing the perverse incentives inherent in a rate base rate of return application and enhancing the incentive properties of PBR.*
> *1(d) How should the efficiency carryover mechanism approved in the first generation PBR plans[f/n omitted] be incorporated into the rebasing process or next generation PBR plans?*

Q8. What do you understand by the term "rebasing" in the context of PBR?

A8. We understand the term "rebasing" to mean establishing new rates to be used as "going-in rates" at the start of a new PBR plan, and we explain our understanding of the purpose of rebasing below. During the term of a PBR plan, base rates in one year are derived from base rates in the prior year by applying the PBR formula, which adjusts for inflation and other factors.[3] During the plan term, changes in base rates from one year to the next do not depend on changes in the utility's recorded costs from one year to the next.[4] However, at the end of the PBR term, the revenue requirement and rates will typically be reset or "rebased", not calculated by means of the PBR formula, and the rebasing process typically will take into account recorded

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[3] In some plans, including the plans for the Alberta electric distribution utilities, *rates* are adjusted in this way. Other designs are possible, including formulaic adjustments to revenues or revenues-per-customer. We refer generically to formula-based rates except where necessary to distinguish between revenue-cap, price-cap and other plan structures.

[4] In some PBR plans there may be elements which give rise to revenues that do depend on recorded costs, such as an earnings-sharing mechanism or a Y-factor or Z-factor adjustment. However, the main part of the PBR formula adjusts revenues by I minus X, independent of recorded costs.

costs (as we discuss in detail below). After rebasing, rates will once again be adjusted going forward from one year to the next by means of the PBR formula, and the changes in base rates will again be independent of changes in recorded costs.

Q9. Why are PBR plans designed so that base rates do not change as recorded costs change from one year to the next of the plan?

A9. The fundamental feature of PBR plans that distinguish them from more traditional cost-of-service approaches to rate regulation is that a utility's revenues under PBR are less strongly correlated with the utility's recorded costs than they would be under a cost-of-service approach.[5] During the term of the PBR plan, as we explained above, changes in recorded costs do not influence changes in base rates (or revenues). As a result, if the utility is successful in efforts to control costs, the financial benefit (relative to the I minus X trend) accrues initially to the utility and its investors. This provides a financial incentive to the utility to search for and implement measures that could reduce costs. Strengthening incentives to control costs is one of the PBR principles adopted by the AUC in the first generation PBR proceeding.[6]

Q10. Why do you characterize PBR plans as resulting in revenues that are "less strongly correlated" with recorded costs than under traditional cost-of-service approaches?

A10. Under traditional cost-of-service approaches, recorded costs influence rates and revenues that will be charged in the year (or years) that is the subject of the proceeding. Typically a cost-of-service proceeding with a forward test year will examine a forecast of test-year costs as well as recorded costs for the most recent year available. As a result, the level of revenues that is approved for the test year can take into account changes in recorded costs up to that most recent year available.

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[5] See, for example, the discussion of "price cap regulatory mechanism" and "pure 'cost-of-service'" in "Incentive Regulation and Its Application to Electricity Networks", *Review of Network Economics*, Joskow, P. L. (December 2008), pp. 550-2.

[6] The first of the AUC's principles is "A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality." (Decision 2012-237, paragraph 28).

However, once rates are set, subsequent changes in recorded costs cannot influence rates (except via the operation of trackers, true-ups or similar mechanisms).

Under the traditional cost-of-service approach previously employed in Alberta, rate cases generally took place every two or three years. Under PBR, the gap between rate cases is longer. Under the traditional cost-of-service approach in Alberta, changes in recorded costs influenced rates with a lag of two to three years, whereas under PBR the lag is now greater.

Q11. If weakening the connection between recorded costs and revenues strengthens the incentive to control costs, what is the purpose of rebasing?

A11. Under PBR, base revenues are the result of formulaic adjustments that do not take into account changes in recorded costs.[7] The effect of increased regulatory lag under PBR is that revenues and costs can diverge: the level of revenues is independent of whether or not efforts to control costs are successful, and this provides strengthened financial incentives to control costs under PBR. However, since PBR base rates do not take account of changes in recorded costs, the benefits of successful cost control (beyond the I minus X trend) accrue only to the utility, and not to customers, during the plan term. The purpose of rebasing is to pass back to customers a share of the benefits of such success by realigning rates with costs going forward.[8]

Since base rates are independent of changes in costs during the plan term, it is possible that achieved returns could be significantly below the authorized level. Low achieved returns may make it difficult for the utility to support necessary investment. Since rebasing brings revenues back into line with recorded costs, it also protects

[7] Revenues under a PBR plan that includes an earnings-sharing mechanism do, in effect, adjust to take some account of changes in recorded costs. Other elements of the PBR plan may provide additional revenues outside of base rates that do take account of some changes in recorded costs (Y-, Z- and K-factors).

[8] "Accordingly, while a fixed price mechanism does well from the perspective of providing incentives to reduce costs it is potentially very poor at "rent extraction" for the benefit of consumers and society because prices may be too high relative to the firm's true cost opportunities." (Joskow, *Op. Cit.*, p. 551). Rebasing is the compromise which passes back the benefits of PBR ("rent extraction", in Joskow's terminology), at the cost of reduced incentives to control cost relative to not rebasing.

against the risk of extended periods of returns significantly below the authorized level.

In some respects, the rationale for rebasing is similar to the rationale for including an off-ramp: one protects against prolonged periods of returns above or below the authorized level, the other protects against extreme differences between achieved and authorized returns.

Q12. In what way does rebasing provide benefits to customers?

A12. As we explained above, during the term of the PBR plan, if a utility is more successful in controlling costs, it will receive the benefits of that success in the form of earnings greater than they would have been but for the success in controlling costs. Thus, during the term of the PBR plan, customers benefit from the trend incorporated into the X-factor but do not receive any additional benefit as a result of the utility's success. As we explain below, during the transition from cost-of-service regulation to PBR, regulators may sometimes include a "stretch factor" in the determination of X. This has the effect of capturing in rates *anticipated* benefits from successful cost control. In contrast, rebasing captures actual benefits (from rebasing forward) of success in controlling costs during the current PBR term. At the end of the plan term, when rates are "rebased" and brought into line with recorded costs, customers see additional benefits of the first PBR term. These additional benefits are in the form of rates in the second PBR plan term that reflect the utility's success in controlling costs during the first term via its impact on the forecast of costs for the rebasing test year.

Q13. Can rebasing benefit utilities?

A13. Yes. Under PBR utilities are financially at risk for unanticipated changes in costs that are not reflected in the PBR formula. If a utility's costs increase more rapidly than its revenues and efforts to control costs are unsuccessful, it will achieve returns below the authorized level. At the end of the plan, rebasing brings revenues back into line with costs. Rebasing is one way in which a PBR plan avoids extended periods of extreme outcomes, and it ensures that the utility has a reasonable opportunity to earn a fair rate of return at the start of the next PBR plan.

Q14. Does rebasing have any other benefit?

A14. Yes. During the PBR term, additional revenue has been authorized to permit recovery of additional costs associated with prudent K-factor capital additions. At rebasing, capital additions that have not been approved through the K-factor process will be reviewed and added to the authorized rate base.

Q15. Does rebasing have the same objective as a cost-of-service proceeding?

A15. Yes, rebasing and traditional cost-of-service proceedings have the same objective: both aim to calculate a revenue requirement and rates that correspond to the utility's costs in the relevant test year. In a jurisdiction such as Alberta that traditionally employs forward test years, the objective of a cost-of-service proceeding is to set rates for the test year[9] that will provide the utility with the expectation of a reasonable opportunity to earn a fair rate of return. If, for the test year, rates are set equal to expected test year costs, including a fair return on expected test year rate base, divided by expected billing determinants, then the objective of providing a reasonable opportunity to earn a fair rate of return will have been met. Similarly, therefore, rebasing should calculate rates that reflect expected test year costs (and billing determinants).

Since they share the same objective, cost-of-service proceedings and rebasing are thus closely related.

Q16. Can you provide some examples from other jurisdictions of the relationship between cost-of-service and rebasing?

A16. In Great Britain, utilities provide detailed business plans and associated expenditure forecasts for each year of the PBR term. A financial model is used to calculate

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[9] We understand that in some proceedings in Alberta multiple forward test years are used.

associated revenue requirements, and the PBR formula is designed to produce revenues equal to the expected revenue requirements in net present value terms.[10] Re-basing and going-in rates are not considered separately, but in essence rates for each year of the plan, including the first year, are developed on a cost-of-service basis. At a high level, the approach in Australia is similar.

In Ontario, a number of different ratemaking approaches are available to the relatively large number of electric distribution utilities in the province. The closest parallel with PBR in Alberta is the "Price Cap Incentive Regulation" approach.[11] Under this approach a cost-of-service proceeding is used to set going-in rates for the next PBR term. The Ontario Energy Board's (OEB's) approach to rebasing is described in Board policy papers,[12] and there are a number of rebasing proceedings each year[13] (because the OEB's practice is to "stagger" PBR plans so that a fraction of the utilities are expected to apply for rebasing each year).

The other approaches are "Annual IR", which allows a utility to extend the term of its PBR plan one year at a time, and "Custom IR", which is designed for utilities with "significantly large multi-year or highly variable investment commitments". The Custom IR approach is described further below.

In British Columbia, FortisBC recently began a new PBR term for 2014–2019.[14] The FortisBC PBR plan provides formula-based revenues that are intended to cover O&M expenses and some capital expenditures (other capital expenditure is covered by a

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[10] In some respects, therefore, the approach to PBR in Great Britain is related to traditional multi-year cost-of-service proceedings in Alberta.

[11] The other approaches are "Annual IR", which allows a utility to extend the term of its PBR plan one year at a time, and "Custom IR", which is designed for utilities with "significantly large multi-year or highly variable investment commitments". The Custom IR approach is described further below.

[12] See, for example, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, Ontario Energy Board, October 2012, p. 13.

[13] See, for example, the April 24th 2015 application of Guelph Hydro, which applied for rebased rates for 2016 in OEB file no. EB-2015-0073. The case resulted in a settlement.

[14] *FortisBC Inc., Multi-Year Performance Based Ratemaking Plan for 2014 through 2018*, BCUC, September 15th, 2014.

separate mechanism, described below).[15] Prior to its current PBR plan, FortisBC was under cost-of-service rates in 2012 and 2013.[16] 2013 authorized figures, determined in an earlier cost-of-service proceeding, were used as the starting point for going-in rates.[17,18] In relation to the O&M component, the BCUC said:[19]

> The Commission Panel determines that an appropriate starting point for the development of the PBR O&M Base is the 2013 Approved O&M. We agree with FBC that this figure has been scrutinized in a recent regulatory proceeding and accept that this is common regulatory practice.

Q17. Are you aware of examples where rebasing has not been done on a cost-of-service basis?

A17. No. However, as we have explained above, cost-of-service and rebasing share a common objective. The details of rebasing differ from one proceeding to another, just as different jurisdictions may use different approaches to setting cost-of-service based rates.

We are aware of examples where adjustments have been made to cost-of-service rates before using those rates as going-in rates for PBR.[20] It is difficult to discern general principles governing when cost-of-service rates should be adjusted before using them as going-in rates for PBR purposes. However, a common theme seems to be that

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15 *Ibid*. Note that the FortisBC plan is described as consisting of a "formula for O&M" and a "formula for capital" (see BCUC decision, section 2.1.2.1). Both base O&M and base capital expenditures are adjusted by (I minus X) and customer growth in subsequent PBR years. However, our understanding is that the effect of these formulas is that base rates adjust with inflation, an X factor, and customer growth, similar to the generic PBR plans in Alberta.

16 *Ibid*., p. 1.

17 *Ibid*., p. iv. Note that, as described above, the FortisBC plan consists of a "formula for O&M" and a "formula for capital". Thus, rather than discussing going-in rates, the BCUC decision discusses how to set the "base amounts" of O&M and capital for the purposes of these formulas, based on previously authorized amounts in a prior cost-of-service year. Our understanding is that this is equivalent to determining going-in rates based on previously-authorized cost-of-service rates.

18 With 2013 rates as "going-in" rates, rates for 2014 are derived by applying the PBR formula to 2013 rates.

19 *Ibid*., p. 186.

20 Including adjustments to going-in rates at the start of the generic plans in Alberta, and the FortisBC example discussed above.

adjustments are considered, and sometimes made, when the proceeding to set going-in rates takes place separate from (and subsequent to) the cost-of-service proceeding, such that additional information may be available in the later proceeding.

Q18. Is a line-by-line examination of recorded and forecast costs needed in a rebasing proceeding?

A18. Not necessarily. In a rebasing proceeding it may be possible to rely on aggregate figures rather than detailed line-by-line forecasts. One of the benefits of PBR is that utilities may test new technologies or new ways of operating in their efforts to control costs, and respond to the strengthened incentives of PBR.[21] A change to utility operations that increases costs in the short term but results in lower costs subsequently may be more feasible under the increased risk/reward structure of PBR than it would have been under traditional cost-of-service regulation. As a result, regulators in jurisdictions where utilities operate under PBR may put more emphasis on outputs and higher-level aggregate costs than on a detailed line-by-line examination of input costs. A line-by-line examination may show variances from one year to the next that are not representative of a long-term trend as the utility explores ways of controlling costs in response to the strengthened incentives of PBR. Higher-level aggregate costs may be more representative.

We note, for example, that in its policy on cost-of-service rebasing proceedings the OEB puts less emphasis on the line-by-line approach that it previously employed for regular cost-of-service rate cases: "the review of OM&A expenses transitioned, beginning with the 2014 cost-of-service applications towards an output- and program-focused review in place of the previous approach, which focused significant attention on discrete elements of the inputs to OM&A expenses."[22,23]

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21 The AUC's first PBR principle is that a "PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality." (Decision 2012-237, paragraph 28). In a competitive market, firms often invest in new technology and new ways of working as they compete with each other.

22 *Filing Requirements For Electricity Distribution Rate Applications, 2015 Edition for 2016 Rate Applications, Chapter 2 Cost of Service*, Ontario Energy Board, July 2015, p. 34.

An approach to rebasing that does not require detailed line-by-line examination of costs is also consistent with the objective of reducing the regulatory burden under PBR.[24]

Q19. Did the AUC address the design of rebasing in the first generic proceeding?

A19. No, the design of rebasing was not addressed in the AUC's decision in the first generic proceeding.

B. THE AUC'S REBASING ISSUES

1(a) How should going-in rates be set for the next PBR term?

Q20. In your experience, how are going-in rates typically set at the start of a PBR plan?

A20. As we described above, the purpose of rebasing is to bring revenues back into line with costs. In some cases, a rebasing proceeding is conducted to determine reasonable costs in a future test year, and rebased rates are determined on that basis. In other cases, cost-of-service based rates have already been determined, and may be adopted as going-in rates (sometimes with adjustments).[25] Where, as in this case, utilities are charging PBR rates at the time of the rebasing proceeding, going-in rates would typically be set by examining the expected level of costs at the start of the next PBR plan. For example, when utilities transition from one IR plan to the next in Ontario, going-in rates are determined in a "single forward test-year cost of service review".[26]

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[23] There is limited experience with the OEB's rebasing approach to date because almost all rebasing proceedings in recent years have been settled through negotiations rather than fully litigated.

[24] Reducing the regulatory burden is part of the AUC's third PBR principle (Decision 2012-237, paragraph 28).

[25] This was the case in the first generation generic PBR proceeding in Alberta. 2012 rates had already been set in separate cost-of-service proceedings.

[26] See *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, Ontario Energy Board, October 2012, p. 13.

Q21. What principles guide the determination of going-in rates?

A21. Going-in rates should be determined consistent with the AUC's PBR principles, and should provide the utility with a reasonable opportunity to earn a fair return at the start of the next PBR term. If cost-of-service rates have already been determined for the year before the first year of the PBR term, those rates could be used directly as going-in rates. It is reasonable to regard going-in rates as being like "year zero" of the next PBR term.[27] If rates at the start of the new PBR term were not realigned with the utility's expected costs, these rates would not be consistent with providing the utility with a reasonable opportunity to earn a fair rate of return, nor would they be consistent with sharing the benefits of the prior PBR term with customers.[28]

Q22. What approach should be followed if, as here, there are no authorized cost-of-service rates for the prior year?

A22. In many cases, when an application is made to determine the parameters of a PBR plan, the utility is charging cost-of-service based rates and these rates are therefore available as a starting point for going-in rates for PBR. For example, this was the situation for the distribution utilities in Alberta at the time of the first generic proceeding. If, as here, there are no existing cost-of-service rates it is necessary to determine cost-of-service based rates for rebasing purposes.

Q23. What should be the objective in determining rebased rates?

A23. Rates at the start of the new PBR plan should be such that expected revenues are sufficient to permit each utility to recover its expected costs, including a fair rate of return. Rebasing on a cost-of-service basis achieves this because rates would be set to recover an explicit forecast of costs, including a return on forecast rate base.

[27] Decision 2012-237, paragraph 75.

[28] The AUC's second PBR principle (Decision 2012-237, paragraph 28).

1(b) Is it necessary to rebase prior to the next generation of PBR? What would rebasing involve?

Q24. What would be the effect of not rebasing?

A24. If rates were not rebased at the start of the next generation PBR plans, customers would not receive their share of the benefits of the utility's successful efforts to control costs during the first generation PBR plans (via its impact on the forecast of costs for the rebasing test year). Equally, the utilities might not begin the next generation plans with a reasonable opportunity to earn a fair rate of return.

Q25. Is rebasing necessary?

A25. Yes. The ability to rebase is an important component of the overall PBR plan design because rebasing provides customers with their share of the benefits of the utility's successful efforts to control costs during the first PBR term (via its impact on the forecast of costs for the rebasing test year), and also ensures that the utility has a reasonable opportunity to earn a fair rate of return at the start of the next PBR proceeding, and is able to make necessary investments. In the jurisdictions with which we are familiar, rebasing takes place between each PBR term.[29,30]

Q26. Are there any alternatives to rebasing other than on a cost-of-service basis?

A26. No. The objective of rebasing is to re-align rates with costs.[31] As such, the objective of rebasing is the same as the objective of a traditional cost-of-service proceeding. However, the details of the approach taken in a cost-of-service proceeding may differ

[29] The PBR plan has a definite term in most jurisdictions (eg, California, UK, Australia). In Ontario the PBR plan for most utilities finishes with rebasing according to a schedule determined by the OEB, and the "Price Cap IR" plans have a fixed term of 5 years. However, in Ontario utilities have the option to extend the PBR plan annually (the "Annual IR" option). See *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, Ontario Energy Board, October 2012, p. 13.

[30] We note that the AUC has previously determined that the current PBR plans should have a fixed term of five years (Decision 2012-237, paragraphs 836-8).

[31] "In practice, "forever" price caps are not typically used in the regulation of distribution and transmission network price levels. Some form of cost-based regulation is used to set an initial value for p_o. The price cap mechanism then operates for a pre-established time period (for example, five years). At the end of this period a new starting price p_o and a new x factor are established after another cost-of-service and prudence or efficiency review of the firm's costs." (Joskow, P. L., *op. cit.*, p. 553).

from one jurisdiction to another, and similarly the details of the approach taken in a rebasing proceeding may also differ.

1(c) What are the arguments for and against inserting a year of cost-of-service regulation after the current PBR term and prior to the start of the next generation PBR plan? What other possible methods are available to rebase rates for the start of the second generation PBR plans? Describe the arguments for and against these alternative approaches in terms of reducing regulatory burden, minimizing the perverse incentives inherent in a rate base rate of return application and enhancing the incentive properties of PBR.

Q27. What questions are raised in the AUC's issue 1(c)?

A27. We explained above that the objective of rebasing is the same as the objective of a cost-of-service proceeding: to realign rates with costs. Therefore three questions are raised by issue 1(c).

- Which year should be the test year for re-basing purposes?
- Should there be an intervening year with cost-of-service rates?
- Should the rebasing procedure employ a full line-by-line cost-of-service approach, or some other method?

Q28. What choices are possible for the test year for rebasing?

A28. Rebasing brings rates back into line with costs. Typically this would mean that the first year after the end of the PBR term, in this case 2018, is the test year for rebasing. With a 2018 test year for rebasing, 2018 rates would be developed on a cost-of-service basis rather than calculated from a PBR formula. 2018 rates would be the going-in rates for the first PBR year (2019), with 2019 rates calculated by applying the PBR formula to the 2018 cost-of-service rates.

An alternative possibility would be to employ a 2017 test year for rebasing. With a 2017 test year, rebased notional 2017 rates would be the going-in rates for calculating 2018 rates by applying the PBR formula to the notional 2017 cost-of-service rates.

Q29. Why do you refer to 2017 rates as "notional" in the case where the test year for rebasing is 2017?

A29. 2017 is the last year of the current PBR plans and 2017 rates will be developed by applying the PBR formula in the regular way. If 2017 is the test year for rebasing, the rebasing proceeding would establish a separate 2017 revenue requirement on a cost-of-service basis, using a forecast of operating costs and rate base for 2017. The rates corresponding to this revenue requirement would be developed but would not be charged to customers in 2017. These rates would form the going-in rates for the next PBR term beginning in 2018, with 2018 PBR rates calculated by applying the PBR formula to the notional 2017 cost-of-service rates. We refer to the 2017 cost-of-service rates as "notional" because they are not charged to customers in 2017.

Q30. What do you understand by the AUC's query in relation to "inserting a year of cost-of-service regulation"?

A30. If, as discussed above, the test year for rebasing is 2018 then the rates charged to customers in 2018 would be cost-of-service based rates, rather than PBR rates. Rebasing to cost-of-service rates with 2018 as an intervening year between PBR terms would be analogous to ENMAX's situation at the start of its 2015–17 PBR plan. ENMAX has applied for PBR rates for 2015–17, with going-in rates based on those established in its 2014 cost-of-service proceeding.[32] Thus, prior to the start of its 2015–17 PBR term, ENMAX had 2014 rates set on a cost-of-service basis, and prior to that 2013 rates were not cost-of-service based but were formula-based (2013 was the last year of ENMAX's 2007–13 FBR plan[33]). Therefore 2014 was a "cost-of-service" year, in contrast to 2013 when rates were set under ENMAX's FBR plan and 2015 for which it is expected that rates will be set under PBR.

Similarly, if the next PBR plans have 2018 going-in rates and 2019 as the first year with PBR rates, 2018 will be an "intervening" cost-of-service year.

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[32] See Section 2.2.2 of ENMAX Power Corporation's 2015-2017 Distribution PBR Application in Proceeding ID 21149, p. 19.

[33] See Decision 2009-035.

Q31. If there were a cost-of-service year after the end of the current generic PBR plans, would going-in rates for the subsequent PBR plan be set equal to the cost-of-service rates in the intervening year, or would they be adjusted in some way?

A31. The purpose of rebasing is to re-align rates with costs, pass back to customers the benefits of successful efforts to control costs during the first PBR plans, and ensure that each utility has a reasonable opportunity to earn a fair rate of return at the outset of the next generation generic plans. As such, if there were a year in which each utility charged cost-of-service based rates, these rates could be used directly as going-in rates for the subsequent PBR plan. The first year of PBR rates (2019) would then be equal to the cost-of-service rates from the prior year, adjusted by (I – X), and with the addition of any necessary capital factor.

If, as is expected to occur in this case in Alberta, the parameters of the next generation PBR plans are determined at the same time as cost-of-service rates for the intervening year are determined, then it may not be necessary to make any further adjustments to going-in rates.

Q32. Using the ENMAX situation you described above as a hypothetical example, would it have been possible to transition between the prior (FBR) plan and a subsequent PBR plan without "inserting a year of cost-of-service regulation"?

A32. Yes. As an alternative to determining 2014 rates on a cost-of-service basis, it would have been possible to determine "year zero" rates for 2013.[34] These rates would not have been charged to customers, since 2013 was the last year of FBR rates. However, notional cost-of-service based 2013 rates could have been used as going-in rates for a 2014–17 PBR plan. 2014 rates would then have been set equal to the notional 2013 going-in rates, increased by (I – X), and with the addition of any necessary capital factor.

[34] On a cost-of-service basis, including any necessary elements such as depreciation studies, rate design and so on.

Q33. If there were no intervening cost-of-service year, would customers somehow "miss out" on the benefits of PBR in the final year of the first PBR plan term?

A33. No. Irrespective of whether there is an intervening cost-of-service year, rates charged to customers in 2017 would be determined under the PBR formula. Rebased going-in rates developed on a cost-of-service basis, whether for 2018 or (notional) 2017, would be based on forecast test year costs that reflect the strengthened incentives operating in the first PBR term. Therefore, whichever year is the test year, customers obtain the benefits of PBR in the final year of the first PBR plan term.

Q34. What are the advantages and disadvantages of an approach with an intervening cost-of-service year?

A34. If there is an intervening cost-of-service year, the test year for the rebasing proceeding is 2018, whereas without the intervening cost-of-service year the test year is 2017. With a 2018 test year, 2018 rates would be based on an explicit forecast of costs for 2018. With a 2017 test year, 2018 rates would be derived from notional 2017 rates by applying the PBR formula (escalating by I minus X and adding incremental capital funding). An advantage of using a forecast for 2018 is that the forecast can incorporate 2018-specific cost information relevant to each utility and would therefore result in base rates that are more closely aligned with expected costs in 2018, particularly if there is evidence to suggest that 2018 costs are expected to differ from 2017 costs in ways that are not reflected in the I- or X-factors. In contrast, rebasing with a 2017 test year would not examine any utility-specific information about expected changes in costs between 2017 and 2018, since 2018 would be calculated by applying the generic PBR formula to each utility's notional 2017 rates.

Assuming that the rebasing proceeding takes place in 2017, if 2017 is the test year, test year costs would be based on forecasting costs for the same year in which the proceeding is taking place, and the test year would not be fully prospective. If 2018 is the test year, test year costs would be fully prospective, since they would be forecasted for the year following the rebasing proceeding.

We understand that if rebasing employs a 2017 test year, with the PBR formula applied to determine 2018 rates, incremental capital funding applications for 2018 would be required. The need to review incremental capital funding for 2018 in as well as conducting multiple cost-of-service rebasing proceedings to set going-in rates could result in an additional regulatory burden in 2017. In contrast, an intervening cost-of-service year for 2018 would not require incremental capital funding in 2018 since 2018 base rates would be cost-of-service based (i.e., would reflect a forecast of all O&M and all capital programs).

The advantages of 2018 as the test year include the ability to incorporate 2018-specific cost information relevant to each utility, thereby resulting in base rates that are more closely aligned with expected costs in 2018. In addition, a 2018 test year would maintain a fully-prospective test year, and could reduce the regulatory burden of multiple simultaneous proceedings by avoiding the need for 2018 K-factor applications.

Q35. Are you aware of any real-world examples of transitioning between PBR plans without an intervening cost-of-service year, similar to what you describe above?

A35. No.

Q36. What do you understand by the AUC's reference to "the perverse incentives inherent in a rate base rate of return application"?

A36. We believe that the AUC may be referring to the fact that, in a cost-of-service proceeding with a future test year, the evidence put forward will include forecasts of test year costs. It is sometimes suggested that utilities would benefit from presenting forecasts that are biased upwards. For example, the AUC has said "In addition, this framework [forecasted test years] also creates an incentive for the companies to provide cost forecasts (both operating and maintenance (O&M), and capital) that are higher than what the company expects to be able to achieve or to provide conservative forecasts of the number customers and other billing units that are lower than what the company expects, thus increasing profits above the approved return."[35]

Q37. Is it problematic to use a forecast test year in a rebasing proceeding?

A37. No. It is inevitable that rate-setting proceedings will involve forecasting of some kind. A rebasing proceeding is no different from a regular cost-of-service proceeding in this regard. It would not be reasonable to ignore evidence as to the expected level of test-year costs when rebasing rates.

Q38. You explained above that the objective of rebasing is to realign rates with costs. What methods can be used for rebasing?

A38. Rebasing aims to realign rates with costs, as a traditional cost-of-service proceeding does. The same methods that have traditionally been used to develop and test cost forecasts in cost-of-service proceedings could therefore be used in rebasing. Examining higher-level aggregate costs is an alternative to a detailed line-by-line examination of input costs. A line-by-line examination may show variances from one year to the next that are not representative of a long-term trend as the utility explores ways of controlling costs in response to the strengthened incentives of PBR. Furthermore, since PBR strengthens incentives to control costs, there may be less need to conduct a detailed line-by-line review of costs to determine prudence.

The choice of method for rebasing—traditional line-by-line, or higher-level aggregate costs—is independent of the choice of test year and whether there is an intervening cost-of-service test year.

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[35] Decision 2012-237, paragraph 11.

1(d) How should the efficiency carryover mechanism approved in the first generation PBR plans[f/n omitted] be incorporated into the rebasing process or next generation PBR plans?

Q39. What is the connection between an efficiency carryover mechanism and rebasing?

A39. An efficiency carryover mechanism (ECM) strengthens incentives to control costs by "carrying over" some of the rewards from successful cost control during one PBR term to the next one. We understand that the ECM approved by the AUC in Decision 2012-237 provides additional returns in the first two years after the end of the first PBR term.

There is no connection between rebasing and the ECM in terms of design or methodology. As a practical matter, any revenue associated with the ECM from the first generic plans would be collected from customers during the first two years of the next PBR term. However, there is otherwise no connection between the ECM revenues (which are associated with performance in the first PBR term) and rates determined in the next PBR term.

Q40. Is the logic underpinning the need for an ECM the same in a second generation PBR plan as in the first generation plan?

A40. Yes.

C. RECOMMENDATIONS ON REBASING

Q41. What approach do you recommend for rebasing?

A41. As explained above, we consider that the objective for a rebasing proceeding should be to set rates that correspond to the utility's expected costs, such that the utility has a reasonable opportunity to earn a fair rate of return. This is the same objective as a regular cost-of-service proceeding.

Typically, the test year for rebasing would be the first year after the end of the PBR term, and there would be an intervening year with cost-of-service based rates. For the Alberta Utilities, this would mean that 2018 would be the test year for rebasing, and

2018 would be an intervening year with rates determined on a cost-of-service basis rather than by applying a PBR formula. Rebased 2018 rates would be the going-in rates for the next PBR term, with 2019 rates calculated by applying the PBR formula.

An approach with a 2017 test year may also be possible. However, a 2018 test year has the advantage that the test year would be fully prospective, 2018 rates would be based on an explicit cost-of-service forecast incorporating 2018-specific cost information relevant to each utility.

We have not considered in detail the practicalities of scheduling multiple rebasing and other proceedings, but we recognize that the alternative of using a 2017 test year could result in additional scheduling challenges (for example, because the 2017 test year approach could require proceedings for additional 2018 capital funding, whereas the 2018 test year approach would not).

Q42. Should the rebasing proceeding employ the same approach as traditional cost-of-service proceedings?

A42. While the objective of cost-of-service and rebasing proceedings is the same, an approach that does not employ the same detailed line-by-line examination of costs as would be employed in a traditional cost-of-service context could be considered in a PBR context. For example, a line-by-line examination may show variances from one year to the next that are not representative of a long-term trend under PBR. Avoiding a detailed line-by-line examination of costs would be consistent with the AUC's objective to achieve regulatory efficiencies through PBR. Furthermore, since PBR strengthens incentives to control costs, there may be less need to conduct a detailed line-by-line review of costs to determine prudence. Nevertheless, whatever approach is taken, the objective of rebasing is to realign rates with expected costs in the test year.

III. THE "X-FACTOR"

A. INTRODUCTION TO THE X-FACTOR

Q43. What issues are you addressing in this section of your evidence?

A43. The second issue on the AUC's list is "Productivity offset (X-factor) in the next generation of PBR". We are addressing issues 2a and 2b:

2(a) How should the X factor be determined?
2(b) Are modifications required to the stretch factor in the next generation of PBR?

We also understand that the X-factor for ENMAX's 2015–2017 PBR plan has been added to the scope of this proceeding, and we address this issue also.[36]

Q44. What is the role of the "X-factor" in a PBR plan?

A44. Under PBR, the base rates[37] in the next year of the plan will be equal to the base rates in the current year, multiplied by (1 + (I – X)). The "I-factor" in the PBR formula represents changes in the price of goods and services that the utility purchases in order to provide utility service, and means that base rates increase with inflation (i.e., before subtracting the X-factor, remain constant in real terms). The X-factor determines the rate at which PBR base rates increase or decrease in real terms. The X-factor adjusts for changes in cost (in real terms) that are to be expected over the term of the plan. The X-factor is sometimes described as a "productivity factor".

In the PBR plan implemented by the AUC in the first generic proceeding, the X-factor was set by measuring the average historical trend rate of productivity growth for the electric distribution industry in the US. We describe below the productivity study on which the AUC relied in setting X for the first generic plans.

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[36] In a letter dated January 29th 2016 and filed in proceeding 21149, the AUC said "given the overlap of X component-related issues, for regulatory efficiency reasons, the Commission will consider ENMAX's X component for the 2015-2017 period within Proceeding 20414, which is the Commission-initiated next generation PBR generic proceeding".

[37] By "base rates" we mean the rates which are adjusted by I minus X under the PBR plan. Other elements of the PBR revenue and rates (such as the K, Y and Z factors) are not adjusted by I minus X.

Q45. Why is it necessary to adjust rates during the PBR plan term?

A45. We explained above that a PBR plan strengthens incentives by weakening the connection between rates and recorded costs. However, while changes in recorded costs over time should not result in corresponding changes in PBR rates, it is important that the profile of PBR rates over time should reflect the expected profile of future costs in real terms.

Q46. Why should the profile of PBR rates reflect the expected profile of future costs?

A46. If costs were expected to increase faster than I minus X, the PBR base revenues would not provide the utilities with a reasonable opportunity to earn a fair rate of return. The AUC's second PBR principle is "A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return."[38]

Q47. How was the X-factor in the current generic PBR plans determined?

A47. The current X-factor is 1.16%. This is composed of a "stretch factor" (which we discuss below) of 0.2% and a "Total Factor Productivity" or TFP trend of 0.96%. The TFP trend came from a study developed by NERA, a consulting firm commissioned by the AUC in the first generic proceeding. NERA's TFP study examined the regulatory accounts of 72 US electric distribution companies over a 37 year period (1972 to 2009), and estimated an average TFP trend across the 72 utilities and the 37 years of 0.96%. The NERA study therefore represents the long-run average TFP trend for the US electric distribution industry.

Q48. In determining an X-factor of 1.16%, did the AUC make any adjustments for differences between the US electric distribution industry and gas and electric distribution utilities in Alberta?

A48. No. The only adjustment made was the stretch factor, which we discuss below. The stretch factor deals with expected differences between the progress of gas and electric

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[38] Decision 2012-237, paragraph 28.

distributors in Alberta under PBR relative to experience under traditional cost-of-service regulation in Alberta, but it does not address any differences between Alberta and the US. In the first generic proceeding the AUC considered that results from the US industry could be applied to Alberta utilities without adjustment.

B. THE AUC'S X-FACTOR ISSUES

2(a) How should the X-factor be determined?

Q49. Did the parties in the first generic proceeding rely on the same NERA TFP study to develop X-factor recommendations?

A49. Several did. ATCO Gas, ATCO Electric and the CCA relied on the NERA TFP study, but used shorter and more recent time-periods rather than relying on the entire 1972–2009 dataset. ATCO's recommended TFP estimate was −0.37%;[39] the CCA's recommendation was +1.15%, whereas NERA's recommendation, based on the entire study period, was +0.96%.[40]

Q50. Have you investigated whether the experience of the electric distribution industry in the US since the AUC's decision in the first generic proceeding is consistent with a TFP trend of 0.96%?

A50. Yes. Since NERA completed its TFP study in the first generic proceeding, an additional five years of data are available. We have updated the NERA TFP study to include this additional data. We used the results of the TFP study for the last five years to test the TFP estimates from the first generic proceeding. We found that the TFP recommendation of 0.96%, based on the whole 1972–2009 dataset, is inconsistent with (statistically different from) the TFP results from the 2009–14

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[39] The ATCO utilities relied on evidence prepared by Dr. Carpenter in the first generic proceeding. See Carpenter reply evidence in Proceeding ID 566 (Exhibit 476.01), pp. 12–13, and see also Workpaper 9.

[40] Decision 2012-237, paragraph 409.

period.[41] The recommendation of −0.37%, based on data from 1994–2009,[42] is consistent with (though still higher than) the TFP results from the 2009–14 period.

Q51. Are the updated TFP study results you report in this evidence the same as you reported previously?

A51. Yes. We have not made any changes to the updated TFP study since filing evidence in the ENMAX 2015–17 PBR proceeding.

Q52. Did you make any changes to the TFP study methodology when you updated it with data from the last five years?

A52. No. While we did not change the TFP study methodology, it was necessary to make some changes to the underlying database in order to update the study.

In addition to adding five years of data, we removed four utilities from the study that no longer publish a FERC Form 1. Also, when we added data for the additional years 2010–14 we checked to make sure that the data for 2010 was reasonably similar in magnitude to the 2009 data, reasoning that any large discontinuities could be indicative of data errors. For one utility in the sample we found a large discontinuity between 2009 and 2010, and we were not able to reconcile the 2010 data with the 2009 data in the original study. Since we were not able to reconcile the data, we removed this utility from the sample.

In addition to FERC Form 1 data, the NERA TFP study uses data on credit ratings and bond yields. We were not able to use the same bond indices that NERA used because we did not have access to the same data providers and because NERA's reports and spreadsheets did not precisely identify exactly which indices were used. We therefore obtained similar data from another provider.

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[41] TFP is a rate of change over time. The five years of data from 2010 to 2014 allow a trend to be calculated that includes the five annual growth rates for 2009/10, 2010/11, 2011/12, 2012/13 and 2013/14. The convention we adopt is to refer to this five-year trend as the period 2009–2014.

[42] i.e., the average of the results for the ten-year and fifteen-year periods.

Q53. What are the results of the analysis for the years 2010 to 2014?

A53. The study results for the additional years are shown in Table 1. The average trend over the 2009/10 to 2013/14 period is −1.25%.

Table 1

Updated TFP study:
TFP Estimates
2009/10–2013/14

	TFP Growth
2010	2.19%
2011	-4.46%
2012	-1.99%
2013	-0.24%
2014	-1.77%
Average	-1.25%

Source: Workpaper 2.

Q54. What were the updated long-run TFP trend results?

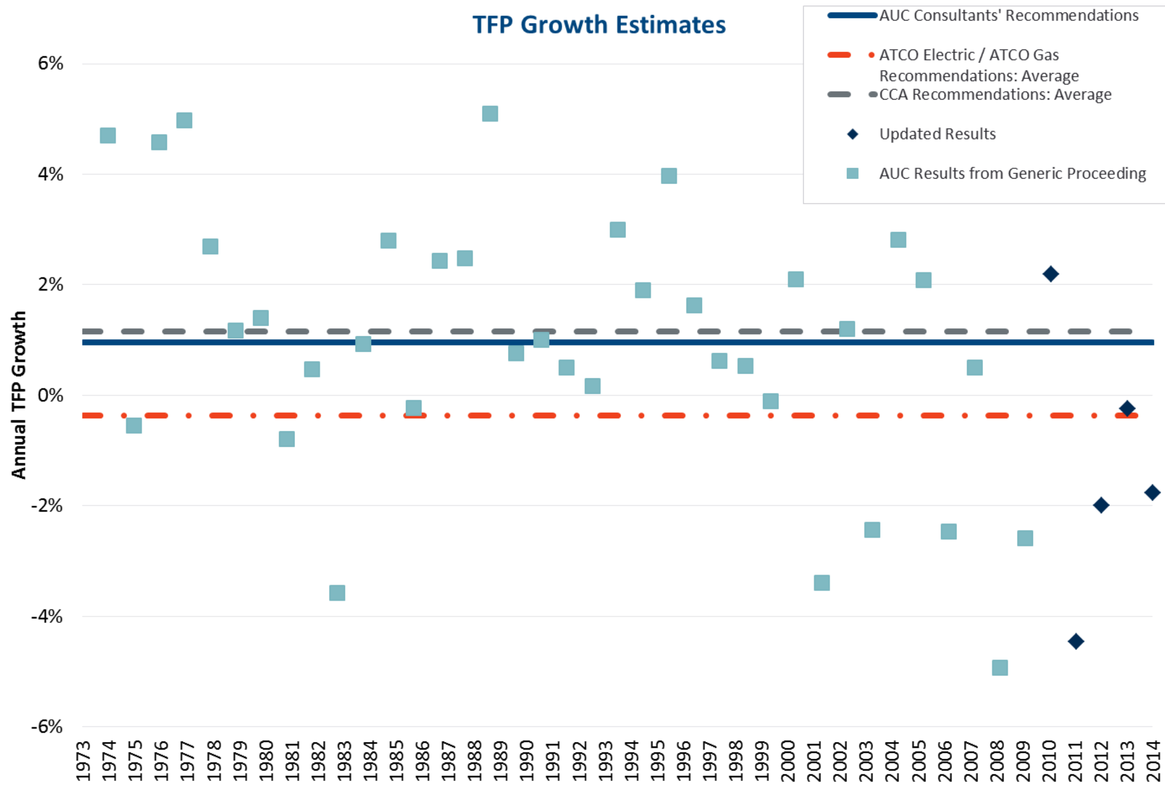
A54. The updated TFP trend results (from combining the original TFP study results with the new results) for the period 1972 to 2014 is 0.70%. The trend over the last 15 years of the study (1999 to 2014) is −0.89%.[43]

Q55. How do the recent results compare with the original TFP study and the TFP trend recommendations in the first generic proceeding?

A55. Figure 1 below shows the individual annual TFP results for 1972–2014. The horizontal lines are the TFP recommendations of −0.37%, +0.96% and +1.15%.

[43] See Workpaper 3.

Figure 1



Source: For AUC Results from Generic Proceeding, see Workpaper 1. For Updated Results, see Workpaper 2. For AUC Consultants', ATCO Electric/ATCO Gas, and CCA Recommendations, see Workpaper 4.

Figure 1 shows that four of the five most recent annual estimates are below the TFP trend estimated from the 1972–2009 period (+0.96%) and the 1989–2007 period (+1.15%). In addition, four of the five most recent annual estimates are closer to the TFP trend estimated from the ten-to-fifteen year period to 2009 (–0.37%) than either of the other estimates. These observations suggest that, of the alternatives available using data up through 2009, the estimate that was most in line with subsequent results is the one based on the ten-to-fifteen year period ending in 2009.

Q56. What tests did you run with the TFP data?

A56. The key question is whether the TFP results from more recent years are different from the TFP results in older years, for example because the structure of the industry has changed, because the older data is unreliable or inconsistently measured, or for some other reason.[44] The first approach we took was to select five-year periods from either the full 1972–2009 data set or from the 1994–2009 period. If either of those two periods is representative of more recent performance, the TFP trend from randomly-selected five year periods would sometimes be higher than the trend from the last five years (an average TFP growth of −1.25%) and sometimes lower, but not systematically different.

We found that, taking continuous five year periods, there is only one period prior to 2009 which shows a TFP trend as low as the results from the last five years. If five years are chosen (without requiring them to be continuous), only around 2.5% of the possible combinations produce a result as low as the average from the last five years. This shows that the results across the 1972–2009 period are very different from the results for the last five years.

When we applied the same methods to the most recent ten-to-fifteen years of the original study (the basis for the −0.37% recommendation), the proportion of historical periods with results below −1.25% is still low, but not as low as for the 1972–2009 period. The ten-to-fifteen year trend is consistent with the results of the last five years, whereas the entire 1972 to 2009 trend is not.

These results are shown in Table 2 below.

[44] Since the 1970s there have been significant changes in the electricity sector in North America: the wholesale market is now competitive in many regions of the US, whereas in the 1970s a much larger proportion of generation was subject to rate regulation; environmental and safety regulations have changed significantly; and in some regions there is competition in retail supply (more commonly for larger customers than households). Some of these changes may not directly impact the distribution function, but they could indirectly impact measured distribution costs if cost allocation has changed over this period.

Table 2

5-year Periods from Original Study in Comparison to the Most Recent 5 Years

		Proportion of periods with TFP trend less than or equal to -1.25%	
		Continuous	Non-Continuous
		[1]	[2]
Full 37 years	[A]	3.0%	2.5%
Most recent 10-to-15 years	[B]	11.8%	20.9%

Sources:
[1A]: Workpaper 5, [5].
[1B]: Workpaper 5, [10].
[2A]: Workpaper 6, [14].
[2B]: Workpaper 6, [28].
Notes:
"Continuous" means taking the average of continuous sets of five years from the original study. "Non-Continuous" means taking the average of random samples of five years. These averages are then compared to the 2009–2014 average.

Q57. Did you also carry out more formal statistical tests?

A57. Yes. We conducted three tests. First, we tested whether an average trend over the original 1972–2009 period was statistically different from the trend over the more recent ten-to-fifteen year period. Second, we tested whether the average trend from the 1972–2009 period was statistically different from the results of the last five years. Third, we tested whether the trend from the ten-to-fifteen year period was statistically different from the results of the last five years. The test results are shown in Table 3.

Table 3

Statistical Tests

Test	T statistic	P value
1: 1972-2009 trend is the same as trend from most recent 10-to-15 years	2.50	0.02
2: 1972-2009 trend is the same as the results from the last 5 years	1.90	0.06
3: Trend from the most recent 10-to-15 years is the same as the results from the last 5 years	0.69	0.50

Sources and Notes:
See Workpaper 7.

Table 3 shows that the 0.96% TFP trend is statistically different from both the average from the more recent ten-to-fifteen year period (−0.37%) and from the results of the last five years (−1.25%). The latter two results, however, are not statistically different from each other.

Q58. Is this statistical analysis similar to the "structural break" analysis discussed by the AUC in the generic proceeding?

A58. The tests we employed are superior to the "structural break" analysis discussed in the first generic proceeding. This is because we are able to look back at the TFP study employed in the generic proceeding and test the TFP trend recommendations produced by that study against the TFP results from the last five years. Thus, these tests take statistical advantage of recent information that was obviously not available to the AUC in the generic proceeding.

A structural break analysis could be used to investigate when the average TFP growth rate changed between 1972 and 2009 (or 2014). However, to evaluate the forecasts made in 2009 this approach is unnecessary because we have the actual forecasts made in 2009 and the subsequent realizations of TFP growth, leading to a straightforward evaluation of the accuracy of the forecasts made in the first generic proceeding. This evaluation shows that a recommendation based on more recent data in the first generic proceeding proved to be consistent with how TFP has evolved over the past five years, whereas a recommendation based on the 1972–2009 period did not.

The tests that we describe above show that a TFP trend based on only the more recent data from the TFP study performs better than a TFP trend based on data back to 1972. It is possible that a structural break analysis might identify a different time period (for example, the last ten years rather than the last fifteen years) that performs better still. We have not performed such an analysis because we are sceptical that it would be reliable given the annual variation apparent in the TFP data.

Q59. What do these results imply about the time period that should be used to estimate a TFP trend in this proceeding?

A59. First, these results show that it would be unreasonable to rely on the entire 1972–2014 period. The last ten-to-fifteen years of data has been shown to be a much better estimate of recent TFP growth than an estimate that also relies on much older data back to 1972. In the first generic proceeding a TFP trend based on data starting in 1994/5 produced a recommendation that was consistent with subsequent TFP growth, whereas the recommendation based on the entire data set was not.

Second, there is significant year-to-year variation in the TFP results, including over the last five years. This means that the choice of start and end date can have an appreciable influence on the resulting trend estimate. We cannot identify any reason why one would choose an end date other than the most recent year for which data is available. In relation to the start date, we would not recommend a year later than ten years prior to the end of the period, because using fewer than ten years of data is more likely to give rise to an estimate influenced by year-to-year variation.[45] A ten-year period would start in 2004/5.

We have not identified any objective method for determining a start date for the period. On the basis of the discussion above, it would be reasonable to use a start year between 1994/5 and 2004/5.

Q60. Why do you say that it would be reasonable to choose a start date between 1994/5 and 2004/5?

A60. The parties in the generic proceeding agreed that at least ten years of data should be used, which means that the latest acceptable start year is 2004/5. The best-performing recommendation from that proceeding was based on data going back to 1994/5.

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[45] See Decision 2012-237, paragraphs 301–2, and references therein.

Q61. What start year do you recommend?

A61. We recommend that the trend be based on the last 15 years of data—that is, using the period 1999/2000 to 2013/14. The corresponding TFP trend is −0.89%. We recommend using the last fifteen years of data because this seems a reasonable compromise between using more data, which risks including out-of-date information, and using less data which risks volatility. The best-performing estimate from the generic proceeding used a combination of a ten-year and a fifteen-year period, but since more data is now available it seems reasonable to opt for the fifteen-year rather than ten-year period.

The trend from 1994/5 to 2013/14 is −0.34% and the trend from 2004/5 to 2013/14 is −1.37%.[46]

Q62. Can you be sure that it would not be reasonable to choose 1972 as the start date?

A62. Yes. The TFP results from the last five years are not consistent with an estimate based on the period 1972–2009. One possible explanation for this is that, as discussed above, the structure of the utility industry in the US was significantly different in the earlier than the later parts of the period.

Q63. Is there any new TFP data available since the update filed in the ENMAX proceeding?

A63. No. We understand that data on utility costs and revenues for 2015 will be available in mid-2016 but is not currently available.

Q64. Did you consider making an adjustment to the TFP trend to take account of the "productivity gap" between the US and Canada?

A64. Over the most recent fifteen-year period for which data is available, official estimates of economy-wide TFP growth for the US and Canada show that the difference

46 See Workpaper 10.

between the trend rate of growth in the US and Canada is about 1.2%—US productivity has improved about 1.2% per year faster than Canadian productivity.[47]

The existence of an economy wide "productivity gap" means that a TFP trend estimated from US data is more likely to be too high than too low when applied in Canada. Unfortunately we have not been able to identify a good way to quantify the adjustment that might be needed: there is no direct evidence on the extent to which the productivity gap may apply in the utility sector. We have adopted an X-factor recommendation based on a US TFP trend without adjustment, while noting that the existence of the productivity gap means that this recommendation is more likely to be too high than too low.

Q65. You mentioned above that the TFP result that the AUC relied on in the first generic proceeding is not consistent with the experience of the industry in the US over the past five years. What about the experience of the industry in Alberta?

A65. We are not aware of any reliable information relating to TFP trends for gas or electric distribution utilities in Alberta. We note that the approach to TFP analysis adopted in Ontario has taken many years to develop, and continues to be controversial and subject to judgement in interpreting the results.[48]

Q66. What X-factor do you recommend?

A66. The updated TFP study suggests that an X-factor in the range −0.37% to −1.37% would be reasonable: the high end of this range (the least negative figure) is a recommendation from the prior generic proceeding that, while higher than the results of the last five years, is not significantly different on a statistical basis; the low end of the range is the trend over the last ten years, which puts more weight on recent data. Our recommendation is an X-factor of −0.89%, which is close to the mid-point of this

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[47] See Workpaper 11.

[48] The OEB determined to use a productivity factor of zero although the productivity study indicated a trend rate of TFP growth of negative 0.3%. (See EB-2010-0379, *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, OEB November 21, 2013 (as corrected on December 4, 2013).)

range and is equal to the results of the updated TFP study for the last fifteen years (the period 1999–2014).

Q67. Should the same X-factor be used for the next generation generic PBR plans and for the ENMAX 2015–17 PBR plan?

A67. Yes. Our evidence on the X-factor that was filed in the ENMAX proceeding is current and we are not aware of any relevant information now available that we did not take into account in developing that evidence. Our evidence on X in the ENMAX proceeding updated the NERA TFP study but did not take into account anything specific to ENMAX. Our recommendation in that proceeding can therefore be adopted in this one.

We are not aware of any reasons for differentiating between the ENMAX 2015–2017 plan and the generic plans for 2018 onwards (other than updating with 2015 data when that becomes available). We explain below why neither the ENMAX 2015–17 plan nor the generic plans should have a stretch factor.

2(b) Are modifications required to the stretch factor in the next generation of PBR?

Q68. What is the purpose of a "stretch factor"?

A68. Under PBR, incentives to control costs are stronger than under traditional cost-of-service regulation, as we explained above. As a result, other things equal, a utility that has operated under cost-of-service regulation for a number of years might be expected to have higher costs than that same utility would have had if it had been operating under PBR for a number of years. Recognizing this expectation, when first implementing PBR regulators may choose to increase the X-factor by adding a "stretch" factor. Where this is done, the purpose of the stretch factor is to *anticipate* additional cost savings that are expected to be achieved under PBR, and set the path of base rates lower than it would have been in the absence of the stretch factor because of the anticipated additional savings. One way to characterize a stretch factor is that it passes on to customers *anticipated* additional savings (over and above those incorporated into the X-factor) immediately which would otherwise, in the absence of the stretch factor, be passed back to customers at the end of the PBR plan (by rebasing).

Q69. How did the AUC describe the purpose of the stretch factor in the first generic proceeding?

A69. The AUC said that "[t]he purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime."[49] The AUC determined that a stretch factor of 0.2% should be included in the X-factor for the first generation generic plans.

Q70. Should a stretch factor be included in the next generation PBR plans?

A70. No. It would not be reasonable to anticipate additional cost savings over and above those implicitly assumed in the X-factor because the distribution utilities in Alberta have been operating under PBR for some time.[50] The purpose of the X-factor is to capture the expected trend in costs for the distribution sector as a whole.

Q71. Does the existence or magnitude of the stretch factor influence the strength of incentives to control costs under PBR?

A71. No. As we explained above, the incentive to control costs comes from the fact that, during the plan term, revenues are independent of changes in costs. The existence or magnitude of the stretch factor does not change the degree to which revenues and costs are independent, and so does not influence the strength of incentives to control costs.[51]

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[49] Decision 2012-237, paragraph 479.

[50] At least five years, by the time that the next generation PBR plans come into effect.

[51] We note that the AUC has previously acknowledged this: "the Commission considers that PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes)" (Decision 2012-237, paragraph 500).

Q72. What would be the consequence of adding a stretch factor if in fact the X-factor already represents the trend rate at which costs can be reduced?

A72. If the X-factor represents the trend rate, adding an additional stretch factor would result in I minus X revenues insufficient to cover the utilities' expected costs, and therefore inconsistent with a reasonable opportunity to earn a fair rate of return.

Q73. Is it fair to say that the X-factor represents the rate at which the utilities' costs are expected to change (in real terms) over the duration of the next generation PBR plans?

A73. Yes. In order for the PBR plan to provide each utility with a reasonable opportunity to earn a fair rate of return, the rate at which base revenues change over time should be consistent with the expected rate of change in the costs which are funded from base rates (i.e., excluding K-factor costs, for example). Base rates will increase at (I – X). If a utility's costs were expected to increase faster than (I – X),[52] the expected profile of base rates would not afford the utility a reasonable opportunity to earn a fair rate of return.

Q74. If, during the PBR plan term, a utility's costs were to change at a rate different from expected, what would be the consequences?

A74. Under the AUC's generic PBR plan design, some costs are treated outside the (I – X) mechanism.[53] However, for those costs that are within the (I – X) mechanism, if costs increase faster than (I – X) then base rates will not keep pace with cost increases, and the utility's ability to earn the authorized return will be impaired. Similarly, if the utility is successful in controlling costs, it may be able to hold cost increases below (I – X) and thereby have the opportunity to earn more than the authorized return. The possibility of earning above or below the authorized return, according to whether the utility is or is not successful in controlling costs, is what provides the strengthened incentive to control costs under PBR.

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[52] After accounting for expected growth.

[53] Some costs are recovered through K-factor, Y-factor or Z-factor revenues.

Q75. If the achieved return on equity is greater than the authorized return on equity, does that signal that the X-factor (or the stretch factor) should be increased?

A75. No. All other things equal, an achieved return greater than the authorized return may signal that a utility has been successful in controlling costs, such that recorded costs have increased more slowly than the corresponding (I – X) revenues, creating the opportunity for the utility to record a return greater than the authorized rate of return.[54] However, the logic of PBR as applied in Alberta is that the TFP study determines the X-factor which in turn determines the rate at which base rates change in real terms. The possibility that costs will increase faster than or slower than (I – X) provides the strengthened incentive for utilities to control costs under PBR. If the achieved return on equity in one plan period were to influence X (or, equivalently, the stretch factor) in the next plan, the incentive properties of PBR would be weakened.[55]

C. RECOMMENDATIONS ON X-FACTOR

Q76. What is your X-factor recommendation?

A76. We recommend that the TFP study should be updated with the new TFP data that has become available since the first generic proceeding. We also recommend that a TFP trend for establishing an X-factor should include only the most recent fifteen years of data. We recommend that the X-factor should not include a stretch factor.

On this basis, our current X-factor recommendation is –0.89%.

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[54] Other factors could also contribute. For example, we understand that the way in which the inflation factor is calculated means that inflation in a particular month could influence recorded costs one or two years before that month's inflation would influence recorded revenues. Inflation in June of 2015 could influence 2015 recorded costs but would influence 2016 (but not 2015) recorded revenues. Inflation in July of 2016 could influence 2015 recorded costs but would influence 2017 (but not 2015 or 2016) recorded revenues.

[55] In Decision 2012-237 the AUC determined that an Earnings Sharing Mechanism should not be included in the generic PBR plans, in part because the ESM would maintain a connection between costs and rates, thereby weakening efficiency incentives. The AUC said "The Commission generally agrees with Dr. Weisman and Dr. Schoech that PBR plans with an ESM provide weaker incentives for efficiency gains, in part because costs and rates are no longer completely decoupled." (Decision 2012-237, paragraph 816)

IV. CAPITAL ADDITIONS

A. INTRODUCTION TO CAPITAL ADDITIONS

Q77. What issues are you addressing in this section of your evidence?

A77. The third issue on the AUC's list is "treatment of capital additions". We address issues 3(a) through 3(c):

3(a) Is an incremental funding mechanism such as capital trackers still required to provide adequate funding for capital additions in the next generation PBR plans?

3(b) If incremental capital funding is needed, 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? For example, while the Commission is not suggesting its support for any particular alternative approach, parties have proposed several alternatives to the capital tracker mechanism during the process of establishing the first generation PBR plans, including:

> *(i) Attempting to determine the average rate of growth of capital in the total factor productivity study and requesting funding for additional growth of capital beyond this level.[f/n omitted]*
>
> *(ii) Modifying the X factor to accommodate the need for higher capital spending (a form of building-blocks PBR plan).[f/n omitted]*
>
> *(iii) Excluding all capital from the going-in rates and the I-X mechanism (a hybrid PBR plan that focuses on operations and maintenance expenses only).[f/n omitted]*
>
> *(iv) Combining the incremental funding needed for certain types of capital beyond what is provided by the I-X mechanism with the going-in rates (referred to as the "K-bar" approach).[f/n omitted]*

(c) If incremental funding is needed, and an alternative to capital trackers is not adopted, can the incentives to achieve cost efficiencies on capital additions be improved and regulatory efficiency be achieved by making modifications to the current capital tracker mechanism to reduce the frequency and complexity of capital tracker–related applications? For example, while the Commission is not suggesting its support for any particular modification to the capital tracker mechanism, parties have proposed several modifications to the capital tracker mechanism during the process of establishing the first generation PBR plans, including:

> *(i) Eliminate or limit the amount of the true-up that is permitted on capital trackers to provide an incentive to be more efficient than the initial forecast for each capital tracker project or program.[f/n omitted]*
>
> *(ii) Eliminate 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.[f/n omitted]*

> *(iii) Other systemic mechanisms to incent project cost efficiencies and minimize regulatory burden, including streamlining options, particularly for multi-year capital tracker programs.*

Q78. How were capital additions treated in the first generic PBR proceeding?

A78. In the first generic proceeding, the AUC determined that base rates escalated by I minus X may not provide sufficient revenues to support necessary capital additions under all circumstances. The AUC said:[56]

> The Commission recognizes that the TFP study used to determine the X-factor adopted by the Commission in this proceeding measures the rate of productivity change of the distribution industry over time necessarily reflecting input costs including the types of capital expenditures and all of the types of year to year fluctuations in the need for capital referred to by the companies. Nevertheless, the Commission acknowledges that there are circumstances in which a PBR plan would need to provide for revenues in addition to the revenues generated by the I-X mechanism in order to provide for some necessary capital expenditures. The way in which this is accomplished is through a capital factor (K factor) in the PBR plan.

The AUC developed a K-factor mechanism that provides additional revenues to support capital programs[57] where forecast additions are expected to result in revenue requirement increases greater than I minus X.

Q79. Why is a K-factor a necessary component of the current generic plans?

A79. The generic PBR plans in Alberta include an X-factor determined on the basis of a long-run TFP trend for the US electric distribution industry. Since the X-factor is defined in this way and is the same for all of the utilities, the evolution of base rates under PBR does not reflect the particular circumstances of each utility,[58] and may therefore not provide sufficient revenue to fund necessary capital investment under all

[56] Decision 2012-237, paragraph 549.

[57] By "capital program" we mean the individual elements of the utility's K-factor, each of which has to meet the four basis points ROE materiality threshold under the current K-factor mechanism.

[58] The AUC's PBR principles include that "A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design." (Decision 2012-237, p. 7)

circumstances. We understand that each of the utilities currently operating under the generic PBR plans has required additional K-factor revenue for these reasons.

Q80. Are similar mechanisms employed elsewhere?

A80. Yes. It is increasingly common for utility regulators to provide additional revenue, over and above revenue from base rates, to support capital additions. In the US, these mechanisms are commonly referred to as "capital trackers", and a large number of utility regulators now permit such mechanisms to be used.[59] In Canadian jurisdictions such mechanisms are also used. In British Columbia, FortisBC is currently operating under a PBR plan that includes a separate capital mechanism.[60] In Ontario, several different mechanisms have been designed to allow utilities to collect additional revenues outside the base PBR revenues to support capital additions. Most electric distribution utilities in Ontario operate under a PBR plan where, as in Alberta, the I- and X-factors are determined in a generic process. These utilities can apply for additional funding to support needed capital investment through the "Advanced Capital Module".[61] In addition, the utilities also have the option of applying for a "Custom IR" plan that can also provide for additional funding for capital expenditures.[62]

In other jurisdictions, capital expenditures during the plan term are taken into account directly by calculating revenue requirements for each year of the plan on a forecast basis.[63]

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[59] A recent survey found that "roughly two-thirds of all utility commissions permit the use of, or are considering the use of, an adjustment clause for new capital investment" (*Adjustment Clauses, A State-by-State Overview*, SNL Regulatory Research Associates – Regulatory Focus, RRA Topical Special Report, October 2, 2015. Report available through SNL Financial LC license.)

[60] *FortisBC Inc., Multi-Year Performance Based Ratemaking Plan for 2014 through 2018*, BCUC, September 15th, 2014 (pp. 170-5) and BCUC Order G-120-15, appendix A (July 22nd, 2015).

[61] EB-2014-0219 *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, Ontario Energy Board, September 2014.

[62] See, for example, EB-2014-0116 (OEB, December 2015), which determined the Custom IR plan for Toronto Hydro for 2015 to 2019. Toronto Hydro's plan contains a "C factor" to support its capital investment program.

[63] This is the approach in the UK, Australia and California, for example.

Q81. What challenges and trade-offs are involved in the design of a mechanism to provide additional revenue to support needed capital investment during a PBR plan?

A81. As with other aspects of PBR plan design, a capital mechanism involves trade-offs. The objective of the capital mechanism is to support needed capital investment but, consistent with PBR principles, the capital mechanism should avoid undue regulatory burden and should not unduly weaken incentives to control costs. In particular, to reduce the risk that necessary investment may not be reflected in additional revenues, the capital mechanism could permit annual applications, but to reduce the regulatory burden of annual filings, the frequency could be reduced. A capital mechanism that trues up for actual additions tracks the actual revenue requirement associated with the additions more accurately, but a mechanism that limits the true up would have stronger incentives to control costs.

We understand that the AUC has found that implementing the K-factor mechanism adopted for the current generic plans was challenging and complex:[64]

> The Commission considers that finding a mechanism that achieves the balance between providing incremental 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. The Commission observes that many highly complex issues involving the interpretation and application of the capital tracker criteria, including grouping issues, the establishment of the accounting test to determine the amount of funding available under I-X, and project assessment to confirm the need for a project, have arisen in the various capital tracker proceedings. The number and complexity of these issues far outstrip any other issues that have arisen from the implementation of the PBR plans.

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64 *Final Issues List, Proceeding 20414*, AUC August 21st, 2015, paragraph 43.

Q82. What considerations are relevant to determining whether capital mechanism filings should be annual or less frequent?

A82. If filings are (or can be) annual, unforeseen capital expenditures can be incorporated into the capital mechanism with minimal lag. In addition, it will be easier to forecast additions accurately if filings are annual than if the forecasts have to extend over multiple years. We understand that some types of capital programs may be more difficult to forecast than others. For example, some types of investment are determined largely by customers or other third parties, and the utility has little control over the timing of the work. For example, distribution contributions to transmission are outside the control of the distribution utility.[65] The degree of risk associated with multi-year forecasts would be greater than for annual forecasts, if the capital mechanism did not permit subsequent true-up, as we discuss below.

The regulatory burden associated with the capital mechanism could be reduced if the fillings were less frequent.

Q83. What considerations are relevant for determining whether a capital mechanism should incorporate truing up for actual additions?

A83. Additions for some capital programs can be challenging to forecast, in either amount or timing. If the capital mechanism incorporates a true up for actual additions, there is less risk associated with forecasting, since forecast additions would determine only the amount of additional revenue initially collected, with under- or over-collection (relative to actual additions) subsequently trued up in a later year. If there is no true up, it is more important that the forecast of additions be accurate. Capital programs that are challenging to forecast should continue to be trued up.

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[65] We note that deferral accounts and true-ups have previously been employed in recognition of this when the distribution utilities were under cost-of-service regulation.

Q84. Would there be merit in having more than one option for the capital mechanism?

A84. Yes. We explained above that some types of capital investment may be inherently more difficult to forecast than others, and that the utility typically has less control over the need for and timing of some types of investment. For these types of investment, the trade-offs discussed above suggest that a better approach would be more frequent filings with the ability to true up for actual additions. For other types of investment where it is easier to prepare an accurate forecast, it might be advantageous to reduce filing frequency and to consider limiting the truing up component.[66] It may therefore be beneficial to treat different capital programs differently. We recognize, however, that having options within the capital mechanism could add complexity. We suggest below modifications to the K-factor mechanism, and the addition of a new "F-factor" mechanism, to permit different capital programs to be treated differently.

B. THE AUC'S CAPITAL ADDITIONS ISSUES

3(a) Is an incremental funding mechanism such as capital trackers still required to provide adequate funding for capital additions in the next generation PBR plans?

Q85. Should the next generation generic plans include a capital mechanism to provide additional funding?

A85. Yes. We are not aware of any approach to PBR similar to the current generic plans in Alberta that does not have a mechanism to provide additional funding for needed capital investment. The AUC's reasoning in the first generic proceeding continues to apply: the design of the I- and X-factors is such that they do not reflect the investment needs of all the Alberta utilities under all circumstances. The experience with K-

[66] When costs are uncertain, theoretical analysis shows that a price cap (i.e., no true up) can lead to higher prices for customers than traditional approaches (true up). "Price caps provide superior incentives for cost reduction, but the more uncertain the environment, the higher the cap must be set in order to keep the regulated firm profitable, and the greater the average ex post price-cost gap. Cost-plus regulation is thus preferred, at high levels of uncertainty." ("Good Regulatory Regimes", *The RAND Journal of Economics*, Schmalensee, R. (1989), p. 418).

factors in the current plans bears this out. A capital mechanism is therefore required in the second generation plans.

3(b) If incremental capital funding is needed, 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? For example, while the Commission is not suggesting its support for any particular alternative approach, parties have proposed several alternatives to the capital tracker mechanism during the process of establishing the first generation PBR plans, including: (i) Attempting to determine the average rate of growth of capital in the total factor productivity study and requesting funding for additional growth of capital beyond this level.[f/n omitted] (ii) Modifying the X factor to accommodate the need for higher capital spending (a form of building-blocks PBR plan).[f/n omitted] (iii) Excluding all capital from the going-in rates and the I-X mechanism (a hybrid PBR plan that focuses on operations and maintenance expenses only).[f/n omitted] (iv) Combining the incremental funding needed for certain types of capital beyond what is provided by the I-X mechanism with the going-in rates (referred to as the "K-bar" approach).[f/n omitted]

Q86. The AUC issues list describes options that could be alternatives to the current K-factor mechanism. What are your views of the suggestion to examine capital investment in the TFP study?

A86. We understand that the K-factor mechanism in the current plans has been developed in a way that allows the process to focus only on a sub-set of each utility's capital investment. Forecasts and business cases have to be prepared for those programs that require additional funding, but the balance of the utility's capital programs do not form part of the K-factor proceeding. In contrast, an approach that compared utility investment plans with an average investment rate from the TFP study (or elsewhere) would mean that all of the utility's capital investment programs would have to be examined. This would add to the regulatory burden of the process and would be inconsistent with the AUC's PBR principles. In addition, the utilities, the AUC and interveners have gained experience with operating the current K-factor mechanism that would be lost if a completely new approach were adopted. While we have not re-examined this approach of examining capital investment in the TFP study in detail, we note that the evidence in the first generic proceeding showed that the rate of capital investment varied considerably across the utilities in the study and across time periods.[67]

Q87. What is your understanding of the AUC's second suggestion (modifying the X-factor)?

A87. Modifying the X-factor (making X less positive or more negative) would create additional base revenue because base rates would increase faster than they would otherwise through the operation of the formulaic I minus X adjustment. This is one of several different ways (others would include modifying going-in rates or creating an F-factor, discussed below) of generating additional revenue that could support needed capital investment. We are not sure how the magnitude of an adjustment to the X-factor would be calculated, except through the kind of forecasting process we discuss below in connection with an F-factor.

Q88. What is your view of the AUC's third suggestion?

A88. The third suggestion from the AUC's issues list was to switch to an O&M-only PBR plan, and fund all capital outside the plan. We note that this option was considered and rejected by the AUC in the first generic proceeding:[68]

> The Commission understands EPCOR's concerns but is itself concerned that excluding all capital from the I-X mechanism will not create new incentives to more optimally make efficient trade-offs between capital and maintenance and may serve to exacerbate the already significant incentives under a rate base rate-of-return framework to prefer capital investment over O&M expenses. In addition, the Commission is not satisfied that there is any acceptable way to create an X factor suitable for use for non-capital-related costs only. Therefore, the Commission does not accept EPCOR's proposal to exclude all capital-related costs from application of the I-X mechanism.

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[67] See Carpenter direct evidence in the first generic proceeding, Proceeding ID 566 (Exhibit 98.02), p. 38-9, and Decision 2012-237, paragraph 556.

[68] Decision 2012-237, paragraph 58.

We agree with the AUC's concerns over the X-factor and limiting the incentives for trade-offs between investment and maintenance. In addition, we observe that an O&M-only approach would exacerbate the AUC's concerns over limited incentives to control capital costs.

Q89. What is your understanding of the AUC's fourth suggestion ("K-bar")?

A89. We understand the "K-bar" approach to involve calculating an additional capital-related revenue requirement in the first year after rebasing, and that this calculation would be similar to that used for a K-factor for the first year of the PBR plan term.[69] However, unlike the current K-factor, the K-bar would continue to provide the same amount of additional revenue in each subsequent year.[70] Also unlike the current K-factor, there would be no true-up.

As with modifying the X-factor, K-bar would create additional revenue that could support needed capital investment. However, we are not aware of any reason to expect that the incremental revenue requirement in each year going forward would be a constant cumulating amount (with or without I minus X escalation).

Q90. What are the key features of a capital mechanism?

A90. As explained above, we consider the key features of the capital mechanism to be the period of time it covers and whether there is a true up. Some capital programs may be more suited to a mechanism with a multi-year forecast and no true up, whereas others may be more suited to a mechanism with a shorter forecast and with a true up.

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[69] We base our understanding on EDTI's final argument in proceeding 2131.

[70] For example, if in year 1 the K-bar revenue was an additional \$2m above base revenues, in year 2 the K-bar revenue would be \$2m from the first year, plus an additional \$2m. Furthermore, both amounts would be escalated by (I – X).

Q91. Please summarize the mechanisms for addressing additional capital funding requirements that you will be discussing further in your evidence.

A91. The relevant range of mechanisms is spanned by considering three specific mechanisms, defined as follows.

- **Existing K-factor**. Programs are identified by applying the AUC's three criteria:[71]

  (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 qualifying programs and amount of additional funding are determined using a forecast of rate base, and the accounting test. Incremental revenue requirements are subsequently trued-up for actual additions.

- **Modified K-factor:** The modified K-factor would operate as the existing K-factor, with the following changes:

  - capital programs within the modified K-factor would be divided into two groups, group one being programs that cannot easily be forecast (for example, where additions have historically varied substantially from one year to the next, and/or the scope and timing of additions are outside the utility's control), and group two being programs for which a reliable two-year forecast of additions can be made;

  - for each group, a two-year forecast of rate base would be prepared every second year, and the existing accounting test would be applied to calculate incremental revenue requirements (over the two years);

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[71] Decision 2012-237, paragraph 592.

- for group one, incremental revenue requirements would be trued-up for actual rate base, whereas for group two there would be no true-up of incremental revenue requirements; and
- for both groups there would be a new forecast of rate base every second year.[72]

The modified K-factor would use the accounting test from the existing K-factor.

- **F-factor**: The F-factor would be used for capital programs for which a reliable forecast can be made for the entire PBR period. The F-factor would operate similarly to group two programs under the modified K-factor, except that the forecast would be made once at the beginning of the PBR plan term for the full term. There would be no true up of incremental revenue requirements during the PBR plan term.

Q92. How do the other approaches mentioned in Q/A87 and Q/A89 above (modified X-factor and K-bar) relate to these mechanisms?

A92. Both "modified X-factor" and K-bar are determined at the start of the PBR plan and are not trued up. In these respects they are similar to the F-factor. However, the amount of additional revenue requirement in each year under the F-factor is based on an explicit multi-year revenue requirement calculation (similar to the current K-factor capital tracker applications for 2016/17, except that the revenue requirement calculations would be based on a forecast for the entire plan term at the start of the term). There is no equivalent calculation for the K-bar, since the K-bar revenue requirement is simply calculated in the first year and escalated from one year to the

[72] For group 1, the revenue requirement impacts of actual rate base being different from forecast are trued-up retrospectively. For group 2, there is no retrospective true-up but rate base is re-forecast every two years. For example, the group 2 K-factor revenue requirement for year 3 would be based on a forecast of year 3 mid-year rate base prepared in the application filed in year 2.

next.[73] Further, as noted above, we are not sure how the magnitude of the modified X-factor would be calculated.

Q93. You mentioned above that it might be beneficial to provide options for different types of capital expenditure to be treated differently under the capital mechanism. Would a combination of K-factor, modified K-factor and F-factor approaches achieve that?

A93. Yes. If the capital mechanism included K-factor, modified K-factor and F-factors, it would be possible for each capital program to receive additional funding under whichever mechanism is the most appropriate for that program.

Q94. What factors might guide the choice of which capital program would be funded by the K-factor, modified K-factor or F-factor mechanisms?

A94. In determining which option should be used for each capital program, the relevant factors are the degree to which it is possible to prepare an accurate forecast for the amount and timing of additions in each program, and the extent to which the scope or timing of additions are under the utility's control or driven by third parties.

(c) If incremental funding is needed, and an alternative to capital trackers is not adopted, can the incentives to achieve cost efficiencies on capital additions be improved and regulatory efficiency be achieved by making modifications to the current capital tracker mechanism to reduce the frequency and complexity of capital tracker–related applications? For example, while the Commission is not suggesting its support for any particular modification to the capital tracker mechanism, parties have proposed several modifications to the capital tracker mechanism during the process of establishing the first generation PBR plans, including: (i) Eliminate or limit the amount of the true-up that is permitted on capital trackers to provide an incentive to be more efficient than the initial forecast for each capital tracker project or program.[f/n omitted] (ii) Eliminate the forecast component of capital trackers, requiring the companies to make

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[73] We understand that the K-bar and F-factor approaches have been described as being similar (or the same). For the avoidance of doubt, in this evidence we rely on EDTI's final argument in proceeding 2131 for the definition of the K-bar. We define the F-factor to be based on an explicit multi-year forecast of capital additions which would be used to forecast additional capital-related revenue requirements in the same way that the calculations are performed under the current K-factor approach.

> ***capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker.[f/n omitted] (iii) Other systemic mechanisms to incent project cost efficiencies and minimize regulatory burden, including streamlining options, particularly for multi-year capital tracker programs.***

Q95. Would limiting the true-up strengthen incentives for controlling the costs of capital programs for which additional funding is being provided?

A95. Yes. Both the modified K-factor (group two) and F-factors would have stronger incentives to control costs than the existing K-factor mechanism. As we also explained above,[74] there is a trade-off between strengthening incentives to control costs and taking on risk that costs could turn out to be different from those forecast for reasons unconnected with success in controlling costs.

Q96. Would there be advantages to requiring the utilities to invest prior to requesting recovery of the costs through an incremental funding mechanism?

A96. No. We are aware that the AUC stated:[75]

> 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.

We are not sure of the basis for this statement, but we do not agree. Any test (presumably, a prudence test) that would be applied to determine whether already-spent capital should give rise to K-factor revenue could also be applied in the context of a true-up.

An ex-post prudence review is not effective as an incentive to control costs because it is a "penalty only" approach which may have the unintended effect of creating disincentives to undertake needed capital investment.[76,77] Finally, an approach that

[74] See Q/A81.

[75] Decision 2012-237, paragraph 614.

[76] We assume that the AUC's proposal would permit the utility to recover the full revenue requirements associated with approved additions on a retrospective basis, since otherwise the utility could not hope to recover the full cost of any investment.

does not permit any incremental funding until after additions are in service would result in "lumpier" patterns of cost recovery and therefore would add to rate volatility. It could also put stress on credit metrics and hinder access to capital.

Q97. Are you aware of any other incremental changes that would improve the current K-factor mechanism?

A97. We explained above that the key features of a capital mechanism are the period over which it operates and whether it is trued-up. Both of these features of the current K-factor mechanism could be adjusted while leaving the structure and mechanics of the K-factor intact. The modified K-factor described above incorporates such adjustments. As we also noted above, rather than applying such changes globally to all capital programs, there would be merit in making them program-specific.

Q98. What is your view of the criteria that might be adopted to determine which capital programs would fall under the current K-factor mechanism and which would fall under an alternative approach?

A98. One set of criteria that could be used are those which we set out above relating to whether reliable forecasts can be made. This is relevant to choosing whether a capital program should qualify under an F-factor (longer forecasts, no true-up) or a K-factor (shorter forecasts, true-up).

We are aware that some capital tracker mechanisms in other jurisdictions are designed to address specific "types" of investment, and only that type of investment would qualify. For example, there are capital trackers which fund gas mains

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[77] "Those who march under the banner of incentive regulation accept the fact that regulators cannot directly, via the prudence test, compel utility managements to minimize cost -- indeed, these advocates tend to ignore the possibility of disallowances entirely. Instead, they argue the current cost-plus regulatory contract must be replaced by an arrangement that provides utilities with specific financial incentives to minimize cost, that is, incentives of the same general form as unregulated competitive markets provide." ("Incentive Regulation for Electric Utilities", *Yale Journal on Regulation*, Joskow, P. L. and Schmalensee, R. (1986), p. 14.)

replacements in some US states.[78] However, these types of trackers are implemented in a different context than that of the generic PBR plans in Alberta. We are also aware that it is sometimes suggested that only capital that is in some sense "extraordinary" and "out of the normal course of business" should qualify for a capital mechanism. We note that in Alberta only the second of these two criteria is used as a criterion under the existing K-factor mechanism, and we are sceptical that it would be possible to identify capital that cannot be funded under I minus X on the basis of the "type" of investment. We understand that the experience gained with the K-factor mechanism to date supports this view (for example, the capital programs funded by the K-factor mechanism for each utility are not the same).

If the adopted capital mechanism has no (or a limited) true-up and operates over an extended period of time, incentives to control costs are strengthened. In addition, there may be benefits from reducing the regulatory burden associated with annual true-ups and annual applications. At the same time, the risk of unexpected outcomes and capital-related revenues that diverge from costs is increased. Therefore the choice of capital mechanism is a trade-off.

Q99. Have you reviewed the paper[79] prepared by Professors Sappington and Weisman that was submitted in this proceeding?

A99. Yes.

Q100. Do you recognize the characterization in the introductory sections of the paper as between rate-of-return regulation and price-based PBR?

A100. Broadly, yes. We would regard "rate-of-return" regulation and "price-based PBR", as the Sappington-Weisman paper uses them, as being on the spectrum of possible regulatory approaches, and in our view most regulatory approaches that are in

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[78] See *Adjustment Clauses, A State-by-State Overview*, SNL Regulatory Research Associates – Regulatory Focus, RRA Topical Special Report, October 2, 2015. Report available through SNL Financial LC license.

[79] *Assessing the Treatment of Capital Expenditures in Performance-Based Regulation Plans*, Sappington and Weisman, September 1st 2015.

practice applied to energy distribution utilities will be at different points on the spectrum and may incorporate elements of both "rate-of-return" regulation and "price-based PBR". For example, traditional cost-of-service regulation previously employed for distribution utilities in Alberta (and currently employed for electric transmission) could be regarded as partly "price-based PBR" because once rates are set they are mostly not trued up,[80] so achieved rates of return can differ from the authorized level. However, traditional cost-of-service regulation in Alberta is also partly "rate-of-return" regulation because rates are adjusted (prospectively) to provide an anticipated authorized rate of return on the existing rate base. We would also characterize the current PBR plans as being partly "price-based PBR" and partly "rate-of-return". As compared to traditional cost-of-service, the term of the plan is longer than the period between traditional rate cases, imparting more "price-based PBR" character. At the same time, the incremental funding provided by the K-factor mechanism has characteristics of pure rate-of-return regulation.[81]

We would also observe that in practice price-cap (or revenue-cap) approaches applied to energy distribution utilities invariably have a periodic cost-based price reset (rebasing).

Q101. How do the different capital mechanisms in the Sappington-Weisman paper relate to the discussion of capital mechanisms in your evidence above?

A101. Our understanding is that several of the capital mechanisms in the Sappington-Weisman paper are similar to the F-factor or modified K-factor approaches we discussed above. We believe that the options described in sections A and B of the paper are different because they would apply to all capital; the option in section D is

[80] We recognize that important true up and deferral mechanisms have been implemented at various times in Alberta.

[81] By "pure rate-of-return regulation" we mean that for capital additions covered by the K-factor, after applying the accounting test, if actual additions turn out to be different than forecast, the revenue-requirement implications of the variance are trued up. This is generally not done in traditional North American regulatory practice, where rates are usually set prospectively (we are aware that electric transmission utilities in Alberta have deferral accounts that similarly true up for some capital addition variances, and that the distribution utilities also had deferral accounts prior to the implementation of PBR).

slightly different because, as the paper points out, the criteria for the OEB's capital module are different from those of the AUC's K-factor; the option in section G is of a different nature because it replaces a forecast of capital expenditures with a historical average of capital expenditures in the capital mechanism calculations; and the option in section H is the "menu" approach which is not discussed in this evidence.

C. RECOMMENDATIONS ON CAPITAL ADDITIONS

Q102. What do you recommend in relation to capital additions?

A102. The AUC has said "Accordingly, the Commission considers that it is reasonable to consider whether modifications to, or substitutes for, the capital tracker mechanism can be made in the next generation PBR plans to improve regulatory efficiency while achieving the balance of objectives identified in Decision 2012-237."[82] We have two recommendations for improving the capital tracker mechanism in the next generation PBR plans. First, the existing K-factor could be modified so that filings are made every two years, with two-year forecasts of additions and incremental funding requirements, and incentives for controlling costs could be strengthened by removing the annual true-up for some of the programs. Second, an optional F-factor mechanism could be available, under which a forecast of additions and incremental funding requirements would be made at the start of the PBR plan for the entire plan term, with no true-up. The determination as to which mechanism might be appropriate for each capital program would include the extent to which the utility is able to make reliable forecasts of additions, and the extent to which the scope and timing of the additions are within the utility's control.

Q103. Does this complete your direct evidence?

A103. Yes.

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[82] *Final Issues List, Proceeding 20414*, AUC August 21st, 2015, paragraph 44.