Alberta Utilities Commission

Errata to Decision 20414-D01-2016

2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities

February 6, 2017

Alberta Utilities Commission
Decision 20414-D01-2016 (Errata)
2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities
Proceeding 20414

February 6, 2017

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Alberta Utilities Commission
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Alberta Utilities Commission

Calgary, Alberta

2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities | **Decision 20414-D01-2016 (Errata)** | **Proceeding 20414**

1. On December 16, 2016, the Alberta Utilities Commission issued Decision 20414-D01-2016,[1] to establish the parameters to be included in the next generation of performance-based regulation (PBR) plans (next generation PBR plans) to be implemented for the 2018 to 2022 period. This decision applies to four electric distribution utilities, ATCO Electric Ltd. (distribution), ENMAX Power Corporation (distribution), EPCOR Distribution & Transmission Inc. (distribution), and FortisAlberta Inc. and two gas distribution utilities, AltaGas Utilities Inc., and ATCO Gas and Pipelines Ltd. (distribution), together referred to as the distribution utilities.

2. Section 48.1 of the Commission's Rule 001: *Rules of Practice* provides that the Commission may correct typographical errors, errors of calculation and similar errors made in any of its orders, decisions or directions. The Commission corrects errors of this nature through the issuance of an errata to the original decision.

3. Upon review of Decision 20414-D01-2016, the Commission has noted a section reference typographical error and required correction.

4. A correction to the subsection numbering is required in Section 5. Currently there are two subsections numbered 5.4. The headings in Section 5 read as follows:

5.4 Commission determination of the X factor for the 2018-2022 PBR plans

5.4 X factor for ENMAX's 2015-2017 PBR plan

5.5 Proposals for a non-negative I-X provision

5. The heading references to sections 5.4 and 5.5 of Decision 20414-D01-2016 are hereby amended to read as follows:

5.4 Commission determination of the X factor for the 2018-2022 PBR plans

5.5 X factor for ENMAX's 2015-2017 PBR plan

5.6 Proposals for a non-negative I-X provision

6. All references to these subsections within the decision will remain as they appeared in the original decision.

7. In accordance with provisions of Decision 20414-D01-2016, the base K-bar calculation involves the use of an accounting test similar to the one currently employed for the capital tracker mechanism used during the current PBR term (albeit with certain modifications).[2] The

[1] Decision 20414-D01-2016: 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, December 16, 2016.

[2] Decision 20414-D01-2016, paragraph 242.

Commission has noted that the order of the steps for the calculation of the interim base K-bar, as outlined in paragraph 254 of the decision, does not follow the order of the K factor calculation process as outlined in paragraphs 498 to 501 of Decision 2013-435[3] and is inconsistent with the resulting terminology set out in paragraph 14 of Decision 3434-D01-2015[4] and adopted in subsequent capital tracker decisions. Specifically, Step 1 in paragraph 254 of Decision 20414-D01-2016 currently corresponds to the second component of the accounting test, defined in Decision 3434-D01-2015, while Step 2 currently corresponds to the first component. This inconsistency does not affect the resulting base K-bar amount calculated, but the Commission considers that it may cause unnecessary confusion for parties calculating and evaluating the results of the base K-bar accounting test. Consequently, the decision will be amended to re-order the steps in paragraph 254 such that the original Step 2 becomes Step 1, consistent with the first component of the accounting test as defined previously. The original Step 1 will, therefore, become Step 2.

8. Further, an error occurred in the placement of the last sentence of the original Step 2, part (i) in paragraph 254 of Decision 20414-D01-2016, which provides instructions for the calculation of the interim base K-bar amount. This sentence reads:

> Distribution utilities should use a four-year average of inflation-adjusted retirements from 2013 to 2016 as an assumption in the accounting test.

9. This sentence should be removed from the original Step 2, part (i) and added as the last sentence of the original Step 1, part (v) of paragraph 254.

10. The changes described above affect all the steps for calculating base K-bar described in paragraph 254 of Decision 20414-D01-2016. Paragraph 254 and the resulting steps are hereby amended to read as follows:

> 254. To summarize, the calculation of interim base K-bar will involve the following steps:
>
> Step 1: Calculate the revenue requirement that is recovered in the base rates under the I-X mechanism for Type 2 K-bar projects or programs for 2018.
>
> (i) Calculate the amount of revenue requirement by program or project recovered in base rates under the I-X mechanism for 2018 using going-in capital-related revenue requirement by program or project, using the method for calculating recovered capital-related revenue requirement from the capital tracker accounting test approved in the current generation PBR plans. There will, however, no longer be a materiality threshold in the accounting test, and the accounting test must be applied to all Type 2 projects or programs, not just those with positive accounting test results.

[3] Decision 2013-435: Distribution Performance-Based Regulation 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

[4] Decision 3434-D01-2015: Distribution Performance-Based Regulation Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers, Proceeding 3434, Application 1610877-1, February 5, 2015.

Step 2: Calculate the projected revenue requirement for Type 2 K-bar projects or programs for 2018.

(i) Distribution utilities on the 2013-2017 PBR plans will determine the capital additions for each K-bar project for each of 2013 to 2016, and ENMAX will determine the capital additions for each K-bar project for 2015 and 2016. K-bar projects include all capital projects or programs that have historical rate base associated with them at the time of the rebasing applications. For non-capital tracker programs from the current generation PBR plans, use the actual capital additions as determined to be prudent in the rebasing application, and for capital tracker projects or programs from the current generation PBR plans, use the actual capital additions approved in the capital tracker decisions. As 2016 actual capital tracker additions will not have received Commission approval at the time of the rebasing application, use the 2016 applied-for actual costs from the 2016 capital tracker true-up application. The 2016 actual costs will be trued up to the amounts approved in the 2016 capital tracker true-up decisions at a later date. ENMAX will not have Commission approval for any of its capital tracker actuals. As such, ENMAX will use the applied-for actuals from its recent capital tracker true-up application for both 2015 and 2016. These amounts will be trued up at a later date.

(ii) Inflate the capital additions to 2017 dollars using the I-X methodology with the approved I factor for each year and the approved X factor for the 2013-2017 PBR plans, which is equal to 1.16. As ENMAX was not on the 2013-2017 PBR plans, it will use the X factor approved for ENMAX's 2015-2017 PBR plan, which is equal to 0.3, as noted in Section 5.5.

(iii) Calculate the average K-bar capital additions, by project, in 2017 dollars for the 2013 to 2016 period, or the 2015 to 2016 period for ENMAX.

(iv) Inflate the average K-bar capital additions by project to 2018 dollars using the I-X methodology with the approved I factor for 2018 and the X factor for the next generation PBR plans.

(v) Calculate the amount of K-bar capital cost incurred for 2018, by program or project, based on the 2018 capital additions from Step 2(iv) and the 2017 mid-year rate base using the method for calculating incurred capital costs from the capital tracker accounting test approved in Decision 2013-435. Distribution utilities should use a four-year average of inflation-adjusted retirements from 2013 to 2016 as an assumption in the accounting test.

Step 3: Calculate the base K-bar.

(i) Calculate the difference between the 2018 K-bar capital-related revenue requirement required on a projected basis by program or project (from Step 2) and the 2018 K-bar capital-related revenue requirement recovered in the base rates by program or project (from Step 1). The result is the capital funding shortfall or surplus amount for each program or project for 2018.

(ii) Sum the capital funding shortfall and surplus amounts, including both negative accounting test results and positive accounting test results without any materiality considerations, for all Type 2 projects and programs from Step 3(i) to get the total interim base K-bar for 2018.

11. For ease of reference, a corrected version of Decision 20414-D01-2016 is appended to this errata decision.

Dated on February 6, 2017.

Alberta Utilities Commission

(original signed by)

Willie Grieve, QC
Chair

(original signed by)

Neil Jamieson
Commission Member

(original signed by)

Henry van Egteren
Commission Member

Decision **20414-D01-2016**

Alberta Utilities Commission

2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities

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Contents

List of tables

1 Decision

1. Customer rates for all Alberta electric and gas distribution utilities are currently set by the Alberta Utilities Commission in accordance with the provisions of performance-based regulation (PBR) plans, the parameters of which were approved by the Commission in Decision 2012-237[1] and Decision 21149-D01-2016.[2] Under these plans, a utility's rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation, less an offset to reflect the productivity improvements the firm can be expected to achieve during the PBR plan period (X factor), plus other specific adjustments. As a result, with the exception of specifically approved adjustments, a utility's revenues are generally no longer linked to its costs; this decoupling of costs and revenues promotes behaviours that increase productivity and decrease costs. The term of the current generation PBR plans expires on December 31, 2017.

2. This decision establishes the parameters to be included in the next generation of PBR plans (next generation PBR plans) to be implemented for the 2018 to 2022 period. This decision applies to four electric distribution utilities, ATCO Electric Ltd. (distribution), ENMAX Power Corporation (distribution), EPCOR Distribution & Transmission Inc. (distribution), and FortisAlberta Inc. and two gas distribution utilities, AltaGas Utilities Inc., and ATCO Gas and Pipelines Ltd. (distribution), together referred to as the distribution utilities.

3. In particular, this decision deals with four main next generation PBR plan parameters: (i) rebasing and the going-in rates for the next generation PBR term, (ii) the X factor, (iii) the treatment of capital additions, and (iv) the calculation of the return on equity (ROE) for reopener purposes.

4. In Section 4 of this decision, the Commission determines that the going-in rates for the next generation PBR plans will be established on the basis of a notional 2017 revenue requirement using costs and capital additions that are rooted in actual data. Cost-of-service (COS) studies, including Phase II applications and depreciation studies, will not form part of the rebasing applications. However, Phase II applications and depreciation studies will be considered by the Commission subsequent to the approval of the going-in rates. Also in Section 4, the Commission determines that the efficiency carry-over mechanism (ECM) "50 per cent" ROE add-on will be applied to the 2017 notional mid-year rate base.

5. In Section 5 of this decision, based on the considerations of industry total factor productivity (TFP) growth and a stretch factor, the Commission determines the X factor for the next generation PBR plans, to be 0.3 per cent. The same X factor of 0.3 per cent will also apply

[1] Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.
[2] Decision 21149-D01-2016 (Errata): ENMAX Power Corporation Distribution 2015-2017 Performance-Based Regulation – Negotiated Settlement Application and Interim X Factor, Proceeding 21149, October 3, 2016.

to the ENMAX 2015-2017 PBR plan. The Commission did not include the provision to limit the value of the I-X index to be non-negative for either plan.

6. In Section 6 of this decision, the Commission determines that capital will be divided into two categories: Type 1 and Type 2 capital. For Type 1 capital, the Commission approves a continuation of capital trackers with some modifications, including the replacement of forecast applications with a placeholder amount, which is detailed in Section 6.4.2. For Type 2 capital, the Commission approves a K-bar methodology, which is detailed in Section 6.4.3. The Commission also determines that negative and positive accounting test results with be netted in each of the Type 1 and Type 2 categories.

7. In Section 7, the Commission determines that the latest information available, be it the initial Rule 005: *Annual Reporting Requirements of Financial and Operational Results* filing or a subsequent ROE restatement filed as part of the annual PBR rates adjustment filing, can serve as a basis for a reopener application. In considering whether a reopener may be required, a distribution utility may be asked for ROE adjustments to account for any outstanding true-up amounts and unusual events that may have affected its earnings.

8. The remaining parameters of the next generation PBR plans, such as the I factor, Y factor, Z factor, and annual reporting requirements, among others, are to be unchanged from those established in Decision 2012-237. These parameters are set out in Appendix 5 to this decision.

2 Procedural summary

9. On May 8, 2015, the Commission issued Bulletin 2015-10,[3] indicating the Commission's intention to proceed with a next generation PBR regulatory regime for the distribution utilities, stating:

> The Commission proposes to continue with PBR regulation of electric and gas distribution utilities in accordance with the five PBR principles that the Commission adopted in the first generation PBR plans. [footnote omitted]

10. The bulletin initiated the present generic proceeding to establish parameters for the next generation PBR plans for the electric and gas distribution utilities under its jurisdiction.

11. The Commission invited interested parties to participate in this generic proceeding by filing a statement of intention to participate (SIP) in the Commission's electronic filing system by May 22, 2015. SIPs were received from ATCO Gas, ATCO Electric (referred to as the ATCO utilities), AltaGas, ENMAX, EPCOR, Fortis, Devon Canada, AltaLink Management Ltd., The City of Calgary, the Consumers' Coalition of Alberta (CCA), and the Office of the Utilities Consumer Advocate (UCA).

12. The bulletin included a preliminary list of issues for parties upon which to comment. Following submissions from various parties, the Commission issued a final issues list identifying the scope of the proceeding on August 21, 2015. Further, the bulletin invited parties to file their proposals for the parameters to apply to the next generation PBR plans and established a

[3] Bulletin 2015-10, Generic proceeding to establish parameters for the next generation of performance-based regulation plans, May 8, 2015.

preliminary timeline for the proceeding. The main process steps, as amended throughout the course of the proceeding, are set out in the table below:

Process step	Deadline
Bulletin 2015-10 issued, initiating this proceeding	May 8, 2015
Parties' comments on the draft list of issues	June 5, 2015
Parties' reply comments on the draft list of issues	June 19, 2015
Final issues list issued by the Commission	August 21, 2015
Next generation PBR plan proposal submissions	March 23, 2016
Information requests (IRs) to parties	April 15, 2016
IR responses from parties	May 6, 2016
Reply evidence from all parties	May 27, 2016
Commission's Round 2 IRs to all parties	June 3, 2016
Sur-rebuttal evidence from all parties to address IR responses that were filed late or were subject to motions	June 13, 2016
Responses from all parties to the Commission's Round 2 IRs	June 17, 2016
Oral hearing	July 6 to July 29, 2016
Argument	August 26, 2016
Reply argument	September 16, 2016

13. In addition to filing their respective plan proposals, AltaGas, ATCO Gas, ATCO Electric, ENMAX and Fortis sponsored the evidence of Dr. P. Carpenter and Dr. T. Brown of The Brattle Group, which included Brattle's TFP growth study as well as its views on the issues in scope for this proceeding. In addition to filing its plan proposal, EPCOR sponsored the TFP growth study by Dr. M. E. Meitzen of Christensen Associates and the evidence of Dr. D. Weisman on the issues in scope for this proceeding. The CCA sponsored the evidence of Dr. M. N. Lowry of Pacific Economics Group Research LLC (PEG), which included PEG's TFP growth study as well as its views on the issues in scope for this proceeding. PEG's rebuttal evidence was written by Dr. Lowry and D. Hovde. The CCA also sponsored the evidence of Mr. J. Thygesen. Messrs. D. Simpson and R. Bell filed evidence for the UCA. The UCA also sponsored the reply evidence by K. Pavlovic, M. Griffing and D. Mugrace of PCMG and Associates LLC, on matters related to a TFP growth calculation. Mr. H. Johnson and Mr. D. Matwichuk filed evidence for Calgary.

14. Following the filing of parties' PBR plan proposal submissions on March 23, 2016, the Commission issued a notice of proceeding inviting interested parties, other than parties who had already filed submissions with the Commission, who wished to participate in the proceeding, to file a SIP by April 1, 2016. No new SIPs were received.

15. The division of the Commission presiding over this proceeding comprises Chair Willie Grieve, QC, who chaired the panel, Commission Member Neil Jamieson and Commission Member Henry van Egteren.

16. The Commission considers the record for this proceeding to have closed on September 16, 2016, when reply arguments were filed.

17. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, reference in this decision to specific parts of the record are intended to assist the reader in

understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to a particular matter.

3 Background

18. In Decision 2012-237, the Commission implemented PBR for certain electric and gas distribution utilities in Alberta. The utilities regulated under this PBR framework are AltaGas, ATCO Electric, ATCO Gas, EPCOR and Fortis. The approved PBR plans that resulted from Decision 2012-237 are for a five-year term from January 1, 2013 to December 31, 2017, referred to throughout this decision as the "2013-2017 PBR plans."

19. The PBR framework approved in Decision 2012-237 provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation (I), which is relevant to the prices of inputs the firms use, less a productivity offset (X), which is relevant to the productivity improvements the distribution utilities are expected to achieve during the PBR plan period. As a result, with the exception of specifically approved adjustments, a utility's revenues are no longer linked to its costs during the PBR term, thereby enhancing incentives for the distribution utilities to improve their productivity.

20. Additionally, under the provisions of the PBR plans approved in Decision 2012-237, a distribution utility may apply for approval of certain rate adjustments to enable the recovery of specific costs where it can be demonstrated that the costs cannot be recovered under the I-X mechanism and where certain other criteria have been satisfied. These adjustments could include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (a Y factor), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (a Z factor). In addition, the Commission determined that a rate adjustment mechanism to fund certain capital-related costs may be required under the approved PBR plans. This rate adjustment mechanism was referred to in Decision 2012-237 as a "capital tracker" with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. The criteria and calculation parameters of the capital tracker mechanism were further developed and clarified in Decision 2013-435[4] and subsequent decisions.[5]

21. ENMAX is also subject to PBR but, unlike the other electric distribution utilities, ENMAX was not directed to file a PBR plan pursuant to Decision 2012-237 because it already had an incentive plan in place at that time. In Decision 2009-035,[6] the Commission approved formula-based ratemaking (or FBR, a term sometimes used as a synonym for PBR) for ENMAX's distribution and transmission services, over the 2007 to 2013 term. Following the

4 Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

5 Decision 3434-D01-2015: Distribution Performance-Based Regulation, Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers, Proceeding 3434, Application 1610877-1, February 5, 2015; Decision 3558-D01-2015: Distribution Performance-Based Regulation, Commission-Initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications, Proceeding 3558, Application 1611054-1, April 8, 2015.

6 Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Proceeding 12, Application 1550487-1, March 25, 2009.

expiration of the ENMAX plan, ENMAX was regulated under a traditional COS framework in 2014. In Decision 21149-D01-2016, the Commission approved a second incentive plan for ENMAX distribution services only, for the years 2015 to 2017. This incentive plan is, in most material respects, with the exception of the X factor, consistent with the PBR plans approved in Decision 2012-237.[7] Decision 21149-D01-2016 approved an interim X factor with the direction that the final X factor for the ENMAX 2015-2017 PBR plan will be determined in the present proceeding.[8] The parameters of the next generation PBR plan for ENMAX for the 2018-2022 period, also will be determined in this proceeding. Throughout this decision, the term "current generation PBR plans" is used to refer to the ENMAX 2015-2017 PBR plan and the 2013-2017 PBR plans for other distribution utilities.

22. In commencing the present generic proceeding to establish parameters for the next generation PBR plans for all electric and gas distribution utilities under its jurisdiction, the Commission indicated in Bulletin 2015-10 that it continued to support the five PBR principles that the Commission adopted in the first generation PBR plans. Those principles were:[9]

> **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3.** A PBR plan should be easy to understand, implement and administer, and should reduce the regulatory burden over time.
>
> **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

23. As noted above, in a letter dated August 21, 2015 (attached as Appendix 4 to this decision), the Commission limited the scope of the present proceeding to four main topics:[10]

(i) rebasing and the going-in rates for the next generation PBR term, discussed in Section 4;

(ii) the X factor, discussed in Section 5;

(iii) the treatment of capital, discussed in Section 6; and

(iv) the calculation of ROE for reopener purposes, discussed in Section 7.

24. The Commission also confirmed that the parameters of the current generation PBR plans (established in Decision 2012-237 for five distribution utilities and for ENMAX in Decision 21149-D01-2016) that were not specifically addressed in the final issues list would continue into

7 Decision 21149-D01-2016 (Errata), paragraphs 45-47.
8 Decision 21149-D01-2016 (Errata), paragraph 53.
9 Decision 2012-237, paragraph 28.
10 Exhibit 20414-X0026, AUC letter - Final issues list, August 21, 2015.

and form part of the next generation PBR plans to be implemented, subject to possible rebasing considerations, at the end of the current generation PBR term. These parameters, which include the type of plan (price cap or revenue cap), I factor, Y factor, Z factor, ECM, service quality provisions and annual reporting requirements, are summarized in Appendix 5 to this decision.

25. In making its decisions in this proceeding, the Commission has considered not only the discrete issues that need to be decided but also how all of the elements of PBR, both those that are being considered in this proceeding and those that continue from the current generation PBR plans, are interconnected and affect each other. In the Commission's view, a PBR plan must be viewed and considered as a whole. It is not enough to pick one element of the PBR plan, argue that it should be eliminated, left unchanged or fixed and consider that to be the end of the conversation. All of the elements of the plan must be considered together in order for the Commission to design a PBR plan that satisfies the PBR principles set out above.

4 Rebasing

26. During a PBR term, the linkage between a utility's revenues and costs of providing utility service is intentionally broken to provide the distribution utility with the flexibility to manage its business in an environment which fosters incentives to seek out and realize process, operational, capital and financial efficiencies so as to reduce costs while maintaining existing service levels. "Rebasing" refers to the exercise of re-establishing the linkage between a utility's revenues and costs with the objective of generally realigning revenues and costs in anticipation of, or at the end of, a PBR plan term. Depending on the context, the word "rebasing" can be used as a noun (the process of rebasing), an adjective (the rebasing process) or as a verb (the process involves rebasing costs and revenues). The rebasing of costs and revenues is used to establish new going-in rates for the next generation PBR plan. If a utility was successful in achieving efficiencies that resulted in cost savings during a PBR plan, the new going-in rates which result from rebasing should reflect these realized savings, thereby benefiting customers throughout the next generation PBR term.

27. Rebasing and setting the going-in rates for the next generation PBR plan was the first item on the final issues list established by the Commission in its letter dated August 21, 2015. All parties indicated that some form of rebasing is necessary prior to the next generation PBR plans,[11] to realign costs and revenues for the benefit of the distribution utilities and customers.[12] In addition, ENMAX noted that rebasing could allow the distribution utilities the opportunity to update relevant COS studies; for example, depreciation studies.[13] The Commission agrees that a form of rebasing is required in order to set the going-in rates for the next generation PBR plans and to review and update certain parameters of the plan.

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[11] Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 33; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 18-19; Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 13; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 27; Exhibit 20414-X0074, EPCOR PBR plan proposal, Appendix A, paragraph 30; Exhibit 20414-X0618, UCA argument, paragraph 3; Exhibit 20414-X0071, Calgary PBR plan proposal, page 10. Although at paragraph 135 of his evidence for the CCA, Exhibit 20414-X0084, Mr. Thygesen stated that a rebasing is not required, he then proceeded to recommend a form of a rebasing in paragraph 175. The CCA, in its argument, Exhibit 20414-X0630, recommended various rebasing approaches, at paragraphs 110-111 and 126.

[12] Exhibit 20414-X0056, Brattle written evidence, PDF page 16, Q/A 24-25.

[13] Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 20.

28. As a result of the inclusion of this issue in the final issues list, the Commission heard evidence on various matters relating to rebasing, as discussed in the sections of this decision that follow. Section 4.1 discusses the importance of going-in rates. Section 4.2 sets out the Commission's determination on the method of rebasing and setting going-in rates for the next generation PBR plans. Section 4.3 addresses the timing and review of Phase II applications and COS studies, such as depreciation studies. Finally, the issue of how to incorporate the ECM amounts approved in the 2013-2017 PBR plans into the rebasing process or next generation PBR plans is discussed in Section 4.4.

4.1 The importance of going-in rates

29. As noted above, the Commission recognizes the interdependence of the various elements of a PBR regime. These include the elements that are at issue in this proceeding and others, such as I, Y and Z, that are not. The significance of this interdependence of the elements of a PBR regime and, in particular, the importance of taking great care in the establishment of the going-in rates became evident from the way in which the positions of parties on the PBR mechanism overall were developed and argued.

30. Broadly speaking, the Commission identified two different views regarding how the three parameters of the PBR plan under consideration in this proceeding (rebasing, X Factor and treatment of capital additions) should be designed and implemented for the next generation PBR term. The first view, formulated from the evidence of the distribution utilities, with the exception of EPCOR, is that the current PBR regime should continue with some amendments such as changing the X factor to something less stringent; continuing with a capital mechanism in much the same form, with some amendments, including the elimination of the true-up on capital additions; and employing an intervening traditional forecast COS test year to realign rates with costs, albeit with a streamlined cost review process. These COS proceedings would likely include many of the typical issues that the distribution utilities might choose to raise in a traditional forecast test year, rate-base rate-of-return proceeding. For example, the distribution utilities subject to the 2013-2017 PBR plans indicated that they expect to file revised depreciation studies, cost allocation studies and Phase II proposals as part of the process to set going-in rates.

31. The second view, formulated by the Commission from the evidence of the interveners (CCA, UCA and Calgary), is that the rates of return earned by the distribution utilities subject to the 2013-2017 PBR plans are too high and that the principal cause of these high earnings appeared to be the capital tracker mechanism. Consequently, in order to ensure that the proper incentives were applied to as much of the distribution utilities' decision making as possible, capital trackers should be eliminated (or constrained significantly) in the next generation PBR plans including the possibility of a "pure" PBR plan with an I-X formula but no additional provision for capital other than as part of a Z factor application. Failing that, the Commission should return to traditional rate-base rate-of-return regulation because capital trackers had resulted in excessive earnings for the distribution utilities, at the same time creating a very large regulatory burden akin to the regulatory burden of traditional rate-base rate-of-return regulation and resulting in large portions of the distribution utilities' capital not being subject to the superior incentives provided by the I-X regime.

32. These two views identified by the Commission evolved as the particular circumstances of ENMAX, which had been regulated for seven years beginning in 2007 under an FBR model, were brought to light and understood during the course of the proceeding. ENMAX had, on

average, earned below its allowed rate of return over its FBR period. Because the ENMAX FBR plan did not include a special capital module, such as capital trackers, ENMAX used its experience to argue against proposals to eliminate capital trackers in the next generation PBR plans. ENMAX argued that had capital trackers been part of its 2007 FBR plan, it would not have earned below its allowed rate of return.

33. In response to ENMAX, the UCA filed evidence arguing that had ENMAX begun its FBR term with rates sufficient for it to earn its allowed rate of return in 2006, it would not have needed capital trackers to earn its allowed rate of return over the FBR term. The UCA's evidence focused the Commission on the importance of going-in rates. This suggested that to the extent that the earnings of the distribution utilities subject to the 2013-2017 PBR plans exceeded their allowed rate of return, this may have been due, at least in part, to the distribution utilities' going-in rates and not due entirely to capital trackers, as the interveners had suggested.

34. All parties agreed on the need to ensure that the going-in rates are not too high or too low, in the sense that they would be only sufficient for the utility to earn the allowed rate of return. The Commission understands that getting the going-in rates correct is critical to the success of a PBR plan. When the Commission repeated the analysis employed by the UCA to get the going-in rates "right" for the distribution utilities subject to the 2013-2017 PBR plans, the Commission found that most of the distribution utilities would not have earned their allowed rates of return over the PBR term if capital trackers had not been included in the plan.

35. The Commission considers that the methodology and analysis used by the UCA and repeated by the Commission has not been fully tested in this proceeding. Therefore, while the analysis is instructive, no definitive or general statement about the merits of capital trackers as they were implemented in the 2013-2017 PBR plans or in ENMAX's FBR plan can be made. However, these observations during the proceeding about the importance of going-in rates being set to provide the distribution utilities with only a reasonable opportunity to earn their allowed rate of return has served to heighten the attention to the setting of going-in rates for the next generation PBR term.

4.2 Rebasing method to set the new going-in rates

36. While the objective of rebasing is stated to be the re-establishment of the linkage between costs and rates, parties pointed out that realigning a utility's revenues with its costs, as part of rebasing, may be done in different ways ranging from traditional COS methods to methods using historical actual costs, with varying levels of adjustments to reflect known or anticipated anomalies. These approaches do not align rates with actual costs but, rather, align rates with forecasted or projected costs using various inputs (including some actual costs) to arrive at the revenue requirement used to establish going-in rates. Two general approaches to rebasing using forecast or projected costs were proposed by the parties in this proceeding.

37. Under the first general approach, advocated by Brattle and the distribution utilities sponsoring its evidence, going-in rates would be established based on forecast costs. Specifically, Brattle proposed setting going-in rates in a COS proceeding based on forecast costs for either 2017 or 2018. If 2017 costs were used, Brattle proposed that the distribution utilities would forecast their 2017 costs and revenue requirement, separate from their 2017 PBR rates. This notional 2017 revenue requirement would not be charged to customers but would be used for the sole purpose of establishing the going-in rates for the next generation PBR plan commencing in 2018. Using 2018 for rebasing would result in an intermediate COS year

between PBR plans. The 2018 rates would be determined on a forecast forward test year basis following a rate case similar to how rates were determined for the distribution utilities in 2012. The next generation PBR plans would commence in 2019 under this proposal using approved 2018 rates as the going-in rates.[14] The distribution utilities sponsoring Brattle's evidence supported using the 2018 intervening COS year.[15] Some of these distribution utilities suggested a streamlined rate proceeding process without a prudence review of actual operating and maintenance (O&M) and non-capital tracker capital costs incurred during the current generation PBR term on the basis that PBR incentives were sufficient to ensure the prudence of these costs.[16] Although ENMAX supported a streamlined approach, from its perspective, this should not be a main objective of the rebasing process.[17]

38. EPCOR and the interveners favoured a different general approach to rebasing that used actual, rather than forecast costs, to calculate going-in rates for the next generation PBR plans. Similar to Brattle, EPCOR suggested using 2017 to determine a notional revenue requirement which would not be charged to customers but would be used for the sole purpose of establishing the going-in PBR rates for the next generation PBR plans.

39. Specifically, EPCOR proposed that the O&M portion of its going-in rates be calculated as a simple average of 2014, 2015 and 2016 actual operating expenditures restated in 2017 dollars. In EPCOR's view, the middle three years of the current generation PBR term are reflective of the strongest incentives. The capital cost portion of EPCOR's going-in rates would be set based on the distribution utility's actual capital costs (i.e., the return and depreciation on EPCOR's 2017 actual mid-year rate base plus 2017 working capital costs) for 2017, the last year of the current generation PBR plans.[18]

40. Calgary agreed with EPCOR's proposed rebasing approach, noting that 2013 could also be included in the calculation of an average O&M expense. Calgary supported using the 2017 actual mid-year rate base for capital rebasing.[19] The CCA accepted EPCOR's selection of years with respect to operating costs, indicating that using an average of 2014-2016 addressed its concern with the potential to lose the efficiencies gained by PBR should the distribution utilities strategically increase costs towards the end of the PBR term.[20] Regarding capital additions, the CCA recommended the use of a 2017 forecast number, rather than actual costs, that does not allow for any cost increases above the I-X level for any capital additions which were under I-X during the PBR term.[21] In his evidence for the CCA, Mr. Thygesen proposed to set going-in rates by simply adjusting the 2017 PBR rates to remove any earnings above the allowed rate of return.[22]

14 Exhibit 20414-X0056, Brattle written evidence, PDF pages 17-18, Q/A28-Q/A29.
15 Exhibit 20414-X0622, ATCO utilities argument, paragraphs 6 and 19; Exhibit 20414-X0624, Fortis argument, paragraph 18; Exhibit 20414-X0619, ENMAX argument, paragraph 13; Exhibit 20414-X0616, AltaGas argument, paragraph 10.
16 Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 19(b); Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 30-31; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 34-35.
17 Exhibit 20414-X0619, ENMAX argument, paragraph 21.
18 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 26-32.
19 Exhibit 20414-X0625, Calgary argument, paragraph 8.
20 Exhibit 20414-X0638, CCA reply argument, paragraph 91.
21 Exhibit 20414-X0630, CCA revised argument, paragraphs 123-126.
22 Exhibit 20414-X0084, CCA evidence of Mr. Thygesen, paragraphs 173-175.

41. Concerned with a possibility that the distribution utilities may take rebasing as an opportunity to increase forecast costs and the resulting necessity to then fully test the forecast, the UCA suggested that the Commission rebase on the 2016 actual operating and capital additions, adjusted for "known and measurable changes." Mr. Bell explained that such changes could include 2017 capital additions, changes in billing determinants, the impact of staff reductions, an inflation adjustment, and one time occurrences such as severance payments.[23]

42. In reaching its determinations regarding the alternative approaches proposed by the parties for rebasing and establishing the going-in rates for the next generation PBR plans, in order to promote the objectives of PBR, the Commission considered the relative merits of the various approaches to rebasing offered by the parties. These objectives (i.e., reduce regulatory burden, minimize the perverse incentives of rate base rate of return applications and enhance the incentive properties of the PBR plan) were communicated in the final issues list.[24]

43. In the Commission's view, achieving these objectives requires balancing of the features of both proposed general approaches to rebasing, as each has its merits and disadvantages. EPCOR and the interveners pointed out that setting going-in rates in a COS proceeding based on forecast costs may create incentives to over-forecast, with the result that customers do not share in the benefits of productivity gains achieved by the distribution utilities in the current generation PBR plans.[25] In testimony, Dr. Weisman, an expert witness for EPCOR, supported this view as reflected in the following extract:

> Forecasts are by their very nature, and the issue of information asymmetries comes up here, are always a source of angst for commissions and regulators. And to the extent they can be avoided, they should. Just because of that information asymmetry, which may be a problem in some cases but not a problem in others, but it also -- the forecast component, in my mind, also renders it a bit less certain that the gains from PBR 1, the first generation PBR, are actually going to be passed on to consumers at the time of rebasing.[26]

44. Additionally, the interveners stated in argument that because of information asymmetry, testing cost forecasts would require the same level of detail as in a traditional COS proceeding. As such, regulatory burden is unlikely to be reduced under this approach to rebasing.[27]

45. Rebasing on actual results addresses these concerns to a large degree.[28] However, some distribution utilities pointed out that rebasing based on forecast costs will reflect changing circumstances in the test year and thus may result in going-in rates better reflective of a reasonable opportunity to earn a fair rate of return.[29] Nevertheless, the principal reason for not using 2017 actual costs is the incentives the distribution utilities have in the final year of current

[23] Exhibit 20414-X0066, UCA evidence of Mr. Bell, PDF pages 26-27, Q/A 21; Exhibit 20414-X0184, UCA-AUC-2016APR15-001.

[24] Exhibit 20414-X0026, Final issues list, paragraph 26.

[25] Exhibit 20414-X0623, EPCOR argument, paragraph 9; Exhibit 20414-X0618, UCA argument, paragraphs 7 and 14; Exhibit 20414-X0630, CCA argument, paragraph 110; Exhibit 20414-X0625, Calgary argument, paragraph 50.

[26] Transcript, Volume 14, page 2973, line 20 to page 2974, line 4 (Dr. Weisman).

[27] Exhibit 20414-X0618, UCA argument, paragraph 16; Exhibit 20414-X0625, Calgary argument, paragraph 38; Exhibit 20414-X0457, PARTIES(Calgary)-AUC-2016JUN03-001(b), PDF page 4.

[28] Exhibit 20414-X0625, Calgary argument, paragraph 55; Exhibit 20414-X0632, UCA reply argument, paragraph 5.

[29] Exhibit 20414-X0622, ATCO utilities argument, paragraphs 12 and 56; Exhibit 20414-X0624, Fortis argument, paragraph 13; Exhibit 20414-X0619, ENMAX argument, paragraph 30.

generation PBR to inflate their costs so as to increase going-in rates for the next generation PBR term. The Commission is also concerned that using the 2017 actual results, which would not be available until May 2018, would not allow for implementation of the next generation PBR rates on January 1, 2018.

46. Having considered the evidence and argument of the parties and after applying its judgement in light of the objectives and purposes of rebasing as described earlier in this section, the Commission does not consider it necessary or desirable to employ a 2018 forecast COS year in order to set going-in rates. Rather, the Commission has determined that it will set going-in rates on the basis of a notional 2017 revenue requirement using actual costs experienced during the current generation PBR term for each distribution utility with any necessary adjustments to reflect individual distribution utility anomalies. The Commission's focus in setting the 2017 going-in rates for each distribution utility will be on using its judgement to estimate the costs that each distribution utility operating under the incentives of the PBR mechanism, unencumbered by incentives inconsistent with the PBR incentives, would have incurred in 2017. It agrees with those parties who submitted using actual pre-2017 costs to develop a notional 2017 revenue requirement, adjusted as required for anomalies, best reflects expected revenues and costs without the distorting influence of the incentives which arise during the last year of a PBR term. The Commission directs each distribution utility to file on or before March 31, 2017, an application to determine a notional 2017 revenue requirement to be used to determine the going-in rates used in setting 2018 PBR rates. The Commission will establish a proceeding for the March 31, 2017 compliance filings. The distribution utilities are directed to file their respective applications under the proceeding number advised by the Commission at a later date. The period of data and mechanisms to be used are specified below.

47. AltaGas, the ATCO utilities, EPCOR and Fortis (utilities on the 2013-2017 PBR plans), in preparing their respective rebasing applications, shall use actual O&M data, 2016 rate base and 2013-2016 actual non-capital tracker data, and 2017 approved capital tracker forecast data. Following the determination of final approved K factor amounts, the going-in rates will be adjusted to reflect the approved actual additions consistent with the capital tracker mechanism established in the 2013-2017 PBR plans approved in Decision 2012-237.

48. The Commission notes that ENMAX was not on the same PBR plans as the utilities on the 2013-2017 PBR plans. The last year of ENMAX's FBR term was 2013 and its intervening COS year was 2014. The actual cost data should reflect the year(s) where the incentives were the strongest resulting in the greatest efficiencies and cost savings. For ENMAX, the time period under consideration will be 2015-2017, the term of its 2015-2017 PBR plan.

49. ENMAX, in preparing its application, shall use actual O&M data, 2016 rate base and 2015 and 2016 actual non-capital tracker capital data. ENMAX will also use its 2017 applied-for capital tracker forecast data. Following the determination of final approved K factor amounts, the going-in rates will be adjusted to reflect the approved actual additions consistent with the capital tracker mechanism approved for ENMAX in Decision 21149-D01-2016.

50. To accommodate the March 31, 2017 filing date for rebasing applications, the Commission directs the distribution utilities to use their available 2016 actual unaudited data as a placeholder for actual 2016 O&M costs and actual rate base. When audited 2016 actual data become available in the May 2017 Rule 005 filings, each distribution utility is directed to file an amendment to their rebasing application to update the 2016 actual O&M and capital data.

O&M component of the revenue requirement

51. Various methods were proposed by parties for using actual costs to determine a notional 2017 revenue requirement. These methods included the use of averages, indexing, or a trending analysis of past expenditures. For example, EPCOR proposed to set the 2017 O&M estimate based on the three-year average actual expenditures for 2014 to 2016, adjusted for 2017 dollars.[30] Calgary proposed using the 2013-2016 average for this purpose.[31] Fortis suggested a forecast based on trending of actual expenditures from the current generation PBR term.[32] Using this method, an O&M forecast would be developed using a year-over-year average of the change in operating costs over the PBR term, and a capital forecast for non-capital tracker expenditures would incorporate the three-year average of actual expenditures for these capital costs.[33] Mr. Bell proposed to index 2016 actuals by I-X to determine 2017 going-in rates.[34]

52. In the Commission's view, given the incentive properties of PBR, rebasing of O&M costs should be based on the lowest O&M cost year during the current generation PBR term, restated to 2017 dollars, with adjustments as necessary to reflect material anomalies specific to that year. Given that distribution utilities will respond differently to the incentives inherent in any PBR plan, the lowest cost year for a particular distribution utility, everything else equal, represents the largest response to the incentives faced by that distribution utility during the PBR term. The Commission is prepared to adjust the 2017 notional revenue requirement estimate obtained by utilizing prior lowest actual O&M expenditures for a particular distribution utility should the distribution utility or interveners provide evidence demonstrating to the satisfaction of the Commission that specific and identifiable adjustments are required to account for unique existing or anticipated material cost anomalies. Allowing for these adjustments that may result in the 2017 costs being lower or higher than they would otherwise be, permits the Commission to recognize the unique circumstances of each distribution utility. The Commission retains its discretion to determine what it considers to be reasonable going-in rates for each distribution utility.

53. Accordingly, the distribution utilities shall prepare a 2017 calculation of O&M costs in the following manner, to be included in a notional 2017 revenue requirement based on actual costs:

Each of the utilities on a 2013-2017 PBR plan shall:

(a) Provide its annual O&M expenditures during the 2013-2016 time period in the format as will be provided by the Commission by January 31, 2017.

(b) Express annual O&M expenditures during the 2013-2016 time period, in 2017 dollars converting as spent dollars to 2017 dollars using their respective approved I-X index and Q factor approved for each year given that I-X reflects the

30 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 29.
31 Exhibit 20414-X0071, Calgary PBR plan proposal, page 53.
32 Exhibit 20414-X0624, Fortis argument, paragraphs 19-20.
33 Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 30-34; Exhibit 20414-X0183, FAI-AUC-2016APR15-001.
34 Exhibit 20414-X0184, UCA-AUC-2016APR15-001(g).

productivity and inflation expectations built into the 2013-2017 PBR plans and the Q factor allows for an adjustment for customer growth.[35]

(c) Utilize the lowest actual annual O&M expenditures, adjusted in accordance with paragraph (b), in preparing its estimate of the notional 2017 revenue requirement.

ENMAX shall:

(a) Provide its annual O&M expenditures for 2015 and 2016, in the format as will be provided by the Commission by January 31, 2017.

(b) Express annual O&M expenditures for 2015 and 2016, in 2017 dollars converting as spent dollars to 2017 dollars using its approved I-X index and Q factor approved for each year given that I-X reflects the productivity and inflation expectations built into its 2015-2017 PBR plan and the Q factor allows for an adjustment for customer growth. ENMAX shall use the X factor approved for its 2015-2017 PBR plan, which is equal to 0.3, as noted in Section 5.5.

(c) Utilize the lowest actual annual O&M expenditures, adjusted in accordance with paragraph (b), in preparing its estimate of the notional 2017 revenue requirement.

Capital component of the revenue requirement

54. With respect to the capital component of the notional 2017 revenue requirement, the Commission has determined that the capital component of the notional 2017 revenue requirement must be divided into capital additions that are subject to I-X in 2017 and those subject to the capital tracker treatment in 2017.

55. Capital additions are generally in respect of investments in long-lived assets. This fact necessitates reliance on longer trends or patterns of past actual expenditures than when coming up with an estimate of O&M costs. Also, the Commission generally agrees with EPCOR’s proposal that in calculating the average, historical numbers should be converted to 2017 dollars.

56. In the Commission’s view, given the incentive properties of PBR, in developing a 2017 estimate for the non-capital tracker component of the notional 2017 revenue requirement and going-in rates, the revenue requirement should be based on the average actual capital additions for years of the current generation PBR plans, excluding the last year, restated to 2017 dollars.

57. Regarding the capital additions subject to capital tracker treatment, the Commission observes that the capital tracker capital additions for the utilities on a 2013-2017 PBR plan were previously scrutinized and approved in prior capital tracker decisions, either on a forecast or true-up basis. Given that the going-in rates will be adjusted to reflect the approved actual additions following the determination of final approved K factor amounts, the Commission will accept on an interim basis, the actual 2016 rate base and the approved 2017 capital tracker forecast for capital additions. For non-capital tracker capital additions, the Commission agrees

[35] The ATCO utilities, ENMAX and Fortis pointed the need to adjust for customer growth in any averaging approach. See: Exhibit 20414-X0637, ATCO reply argument, paragraph 53; Exhibit 20414-X0619, ENMAX argument, paragraph 33; Exhibit 20414-X0624, Fortis argument, paragraph 43.

with parties that non-capital tracker additions can generally be assumed to be prudent,[36] because these costs were subject to the incentive properties of the I-X mechanism.

58. The Commission notes that ENMAX does not have any capital tracker capital additions approved either on a forecast or actual basis. Therefore, the Commission will accept on an interim basis, 90 per cent of the applied-for 2017 capital tracker forecast for capital additions.

59. Given the above, the distribution utilities shall prepare a 2017 calculation of capital costs in the following manner, using the following assumptions in developing the notional 2017 revenue requirement and going-in rates based on actual costs:

Each of the utilities on a 2013-2017 PBR plan shall:

(a) Use the actual 2016 closing rate base, as the starting point.

(b) Adjust the rate base, removing related utility assets as directed in prior utility asset disposition proceeding decisions,[37] as applicable.

(c) For the non-capital tracker component, add to the 2016 closing rate base, the average actual capital additions for years 2013 to 2016 for non-capital tracker capital in order to estimate this portion of the 2017 rate base, converting the 2013 to 2016 spent dollars to 2017 dollars using their respective approved I-X index and Q factor approved for each year.

(d) For the capital tracker component, add the approved 2017 forecast capital tracker capital additions to the 2016 closing rate base in order estimate this portion of the 2017 rate base, to be used in developing the notional 2017 revenue requirement and going-in rates.

(e) Apply 2017 depreciation using the distribution utility’s most recent approved depreciation methodologies applied to the 2016 actual closing rate base, to the notional non-capital tracker 2017 additions referred to in paragraph (c) and to the 2017 forecast capital additions referred to in paragraph (d). Also apply 2017 notional retirements and contributions (net of amortization of contributions) based on the average actual retirements and contributions for years 2013 to 2016 for non-capital tracker capital, converting the 2013 to 2016 dollars to 2017 dollars using their respective approved I-X and Q factor approved for each year. These assumptions will be used in developing the notional 2017 revenue requirement and going-in rates.

ENMAX shall:

(a) Use the actual 2016 closing rate base, as the starting point.

(b) Adjust the rate base, removing related utility assets as directed in prior utility asset disposition proceeding decisions, as applicable.

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36 Transcript, Volume 13, page 2590, line 25 to page 2591, line 14 (Mr. Zurek); Exhibit 20414-X0255, ATCO-AUC-2016APR15-002(b).

37 For example, Decision 20271-D01-2015: FortisAlberta Inc., Disposition of Land in High River, Proceeding 20271, August 31, 2015 and Decision 3206-D01-2015: EPCOR Distribution & Transmission Inc., Disposition of Substation Property, Proceeding 3206, Application 1610546-1, February 25, 2015.

(c) For the non-capital tracker component, add to the 2016 closing rate base, the average actual capital additions for years 2015 and 2016 for non-capital tracker capital in order to estimate this portion of the 2017 rate base, converting the 2015 and 2016 spent dollars to 2017 dollars using its respective approved I-X index and Q factor approved for each year.

(d) For the capital tracker component, add 90 per cent of the 2017 forecast capital tracker capital additions to the 2016 closing rate base in order estimate this portion of the 2017 rate base, to be used in developing the notional 2017 revenue requirement and going-in rates.

(e) Apply 2017 depreciation using the distribution utility's most recent approved depreciation methodologies applied to the 2016 actual closing rate base, to the notional non-capital tracker 2017 additions referred to in paragraph (c) and to the 2017 forecast capital additions referred to in paragraph (d). Also apply 2017 notional retirements and contributions (net of amortization of contributions) based on the average actual retirements and contributions for years 2015 and 2016 for non-capital tracker capital, converting the 2015 and 2016 dollars to 2017 dollars using its respective approved I-X and Q factor approved for each year. These assumptions will be used in developing the notional 2017 revenue requirement and going-in rates.

60. In light of the future going-in rate adjustments associated with the yet to be approved true-up of K factors, the notional 2017 revenue requirement and going-in rates for each distribution utility will be approved on an interim basis only. Once all capital tracker actual amounts are approved on a final basis and all other going-in rates adjustments required pursuant to any approved changes in depreciation expense as discussed in Section 4.3 are finalized, the going-in rates will be finalized effective January 1, 2018, with rate adjustments made on a prospective basis, with subsequent adjustments.

61. The Commission does not consider that an adjustment to O&M costs and non-capital tracker capital costs is required to going-in rates to reflect actual 2017 costs because the application of the I-X mechanism and Q adjustment to the rebasing amounts determined using the mechanisms referred to above, plus any adjustments for anomalies as discussed below, should be sufficient for the purposes of determining going-in rates. This is reinforced by an understanding that some of these O&M and non-capital tracker capital costs will increase while others will decrease or disappear in 2017 while the entire amount established using these mechanisms will be adjusted by I-X and Q in setting the going-in rates for the next generation PBR term.

62. The notional 2017 revenue requirement used to determine going-in rates will be based on past actual expenditures. The Commission agrees with those parties who considered that this approach would reduce regulatory burden because a line-by-line review of actual costs for prior years would not be necessary as the O&M costs and non-capital tracker capital costs were subject to PBR incentives.[38] Regarding the estimates of capital additions subject to capital tracker treatment, the Commission agrees with the views of the distribution utilities that since these capital additions are (or will be in the case of ENMAX), tested under the capital tracker mechanism, no further testing or duplication of information would be required as part of the

[38] Exhibit 20414-X0056, Brattle written evidence, page 11, A18; Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 26; Exhibit 20414-X0255, ATCO-AUC-2016APR15-002.

rebasing process for previously approved actual or forecast costs subject to capital tracker treatment.[39] Therefore, an examination of higher-level aggregate costs and methods used to determine the 2017 notional revenue requirement, together with an examination of applied-for cost additions or reductions due to present or anticipated cost anomalies may be sufficient to test the rebasing applications.[40] [41]

63. As noted earlier in this section, there was widespread recognition among the parties that, unless streamlined, rebasing applications for six distribution utilities may result in significant regulatory burden. The Commission agrees. To aid in the assessment of their rebasing compliance applications to this decision, the Commission directs the distribution utilities to provide their Rule 005 reports for each of 2013, 2014 and 2015, and their available 2016 actual data (with a view of updating them when the 2016 Rule 005 report becomes available). The distribution utilities are also required to fill out the template that the Commission will provide by January 31, 2017, and to fully describe any deviations from the utilization of the lowest actual annual O&M expenditures in arriving at the 2017 notional revenue requirement estimate.

64. The Commission considers that the mechanics of calculating going-in rates should follow the same process as set out in Decision 2012-237 and subsequent compliance filing decisions. To highlight a few specific areas, the distribution utilities should continue to rely on the mid-year rate base convention.[42] Any amounts to be treated as flow-through items in the next generation PBR plans should be removed from going-in rates.[43]

4.3 Phase II, depreciation, and other COS studies

65. Several issues related to the timing and nature of rebasing were the subject of submissions during the proceeding. Among these issues was the timing and incorporation of results arising from Phase II proceedings. The purpose of Phase II proceedings is primarily to revise rate design and rate class cost allocations used in determining how much of the revenue requirement should be recovered from each customer class and the billing determinants that will apply to each class. In a PBR environment, cost allocation methodologies based on approved Phase II methodologies and updated billing determinants are used to establish K, Y and Z factor rate adjustments by rate class.[44]

66. With the exception of EPCOR, all distribution utilities proposed filing Phase II applications subsequent to filing rebasing applications.[45] EPCOR preferred to base its going-in rates on an new Phase II rate design methodology to be approved prior to filing a rebasing application.[46] The UCA and the CCA expected that a Phase II application would follow after the

[39] Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 26; Exhibit 20414-X0255, ATCO-AUC-2016APR15-002; Exhibit 20414-X0624, Fortis argument, paragraph 33.
[40] Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 30; Exhibit 20414-X0157, EPC-AUC-2016APR15-002.
[41] Exhibit 20414-X0625, Calgary argument, paragraph 61; Exhibit 20414-X0624, Fortis argument, paragraph 22; Exhibit 20414-X0637, ATCO utilities reply argument, paragraph 52.
[42] Decision 2012-237, paragraphs 101-103.
[43] Decision 2012-237, paragraph 719.
[44] Decision 2012-237, paragraphs 977, 982 and 993.
[45] Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 39; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 53-54; Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 35; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 64.
[46] Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 65.

revenue requirement was determined in the rebasing process,[47] with rates adjusted accordingly as part of the annual PBR rate adjustment filings.[48]

67. To keep the scope of the distribution utility specific next generation PBR plan applications limited for regulatory efficiency and to provide rate certainty with respect to the going-in rates at the start of the next generation PBR term on January 1, 2018, the Commission agrees with the position of the UCA and the CCA. New approved Phase II methodologies supported by updated rate class cost allocation studies or rate design studies should not be filed prior to the commencement of the next generation PBR plans, and since rate class allocations are revenue-neutral, they may be filed and implemented on a go-forward basis any time during the PBR term. The Commission has previously employed this approach in Decision 2014-018,[49] where it accepted Fortis' proposal to incorporate a new cost allocation and rate design set out in an approved Phase II application on a go-forward basis during the current generation PBR term, rather than reflecting the updated design and cost allocations through an adjustment to going-in rates.[50] Therefore, the Commission will not accept Phase II applications intended to establish a new rate design or cost allocation among rate classes to take effect upon the commencement of the next generation PBR plans. Phase II applications will be accepted for consideration which are intended to take effect sometime following the commencement of the next generation PBR plans on a prospective basis.

68. Following the approval of any updated Phase II study during the term of the next generation PBR plans, the Commission will not consider further Phase II applications. This is consistent with the determination in Decision 2012-237.[51]

69. Parties also expressed the need to update other COS studies, including depreciation studies, to be approved in the rebasing proceedings.[52] ENMAX and AltaGas anticipated that, as part of its rebasing application, a distribution utility would have an opportunity to apply for approval of one or more of the following studies: depreciation, pension, compensation, shared services, and necessary working capital.[53] Fortis and EPCOR proposed that depreciation rates used to determine its forecast or actual rate base for the next generation PBR term would be based on a depreciation study that would form part of their rebasing applications. EPCOR submitted that if depreciation rates were not approved when its PBR going-in rates were approved, the rates should be trued-up following final approval of the depreciation rates.[54] Fortis stated that according to Section 122(l)(a)(i)[55] of the *Electric Utilities Act*, utilities should be given

47 Exhibit 20414-X0618, UCA argument, paragraph 13; Exhibit X0084, CCA evidence of Mr. Thygesen, paragraph 179.

48 Exhibit 20414-X0066, UCA evidence of Mr. Bell, PDF page 28,Q/A 24, Exhibit X0084, CCA evidence of Mr. Thygesen, paragraph 180.

49 Decision 2014-018: FortisAlberta Inc., 2012-2014 Phase II Distribution Tariff, Proceeding 2363, Application 1609211-1, January 27, 2014.

50 Decision 2014-018, paragraph 329.

51 Decision 2012-237, paragraph 996.

52 Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 20; Exhibit 20414-X0637, ATCO reply argument, paragraph 53; Exhibit 20414-X0624, Fortis argument, paragraph 21; Exhibit 20414-X0618, UCA argument, paragraph 9.

53 Exhibit 20414-X0157, EPC-AUC-2016APR15-001; Exhibit 20414-X0289, AUI-AUC-2016APR15-001(d).

54 Exhibit 20414-X0183, FAI-AUC-2016APR15-001 and FAI-AUC-2016APR15-002(b); Exhibit 20414-X0256, EDTI-AUC-2016APR15-004(b) and (c).

55 Section 122(1) When considering a tariff application, the Commission must have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover

an opportunity to update depreciation parameters.[56] Further, Fortis and the ATCO utilities described the need for a depreciation study in the context of setting a K-bar factor amount.[57] In a similar vein, the ATCO utilities submitted that rebasing forecasts would require an update to depreciation rates reflected by current depreciation and other studies.[58] The UCA and the CCA submitted that a depreciation study would be required if a utility wished to change its depreciation rates at rebasing.[59] Calgary expressed its view that a depreciation study is not necessary for rebasing.[60]

70. The Commission will provide the distribution utilities with an opportunity to update depreciation studies if they choose. However, the Commission considers, for purposes of regulatory efficiency, updated depreciation studies may not be included in distribution utility rebasing applications. Distribution utilities may file separate depreciation related applications during the first year of the next generation PBR term, i.e., in 2018, and the Commission will make its determinations based on the merits of such applications at that time. Going-in rates will be adjusted effective January 1, 2018, on a prospective basis, to reflect any changes in approved depreciation parameters.

71. Following the approval of any updated depreciation study, any subsequent depreciation changes during the next generation PBR plans may be reflected in rates only if they are eligible for Z factor treatment, and may not be accounted for through either a Y factor[61] or a K factor.[62] [63] This practice is consistent with the practice established in Decision 2012-237.

72. With respect to pension, compensation, shared services, and necessary working capital[64] costs, the Commission considers that these types of costs, to the extent they fall under the I-X mechanism, adjusted by Q, are no different than other types of operating costs and can be adequately reflected in the rebasing process through the O&M mechanism and non-capital tracker capital cost averaging mechanism described above. The Commission may also direct the distribution utilities to undertake certain studies as part of the ongoing rate regulation initiative.

4.4 Efficiency carry-over mechanism

73. A utility's incentive to find efficiencies weakens as the end of the PBR term approaches, in part because there is less time remaining for the utility to benefit from any efficiency gains. The purpose of an efficiency carry-over mechanism (ECM) is to address this problem by permitting the utility to continue to benefit from any efficiency gains after the end of the PBR

(a) the costs and expenses associated with capital related to the owner's investment in the electric utility, including … (i) depreciation, …

56 Exhibit 20414-X0633, Fortis reply argument, paragraphs 17-18.

57 Transcript, Volume 9, pages 1812-1815 (Ms. Sullivan); Exhibit 20414-X0565, undertaking response by Mr. Grattan to Ms. Sabo at Transcript, Volume 7, page 1425, line 25 to page 1426, line 10, response to bullet 2.

58 Exhibit 20414-X0454, PARTIES(ATCO)-AUC-2016JUN03-002(a)(ii).

59 Exhibit 20414-X0618, UCA argument, paragraph 9; Transcript, Volume 10, page 1954, lines 7-16 (Mr. Thygesen).

60 Exhibit 20414-X0625, Calgary argument, paragraph 59; Transcript, Volume 16, page 3307, lines 14-22 (Mr. Matwichuk).

61 Decision 2012-237, paragraph 688.

62 Decision 20407-D01-2016: EPCOR Distribution & Transmission Inc., 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast, Proceeding 20407, February 7, 2016, paragraphs 607-616.

63 Decision 20497-D01-2016: FortisAlberta Inc., 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast, Proceeding 20497, February 20, 2016, paragraphs 137-143.

64 Exhibit 20414-X0157, EPC-AUC-2016APR15-001; Exhibit 20414-X0289, AUI-AUC-2016APR15-001(d).

term. As Brattle noted, an ECM strengthens incentives to control costs towards the end of the PBR term by "carrying over" some of the rewards from successful cost control from one PBR term to the next one.[65] The Commission approved an ECM in Decision 2012-237 to encourage distribution utilities to continue to make cost-saving investments near the end of the PBR term and discourage gaming regarding the timing of capital projects or programs.[66]

74. In accordance with the terms of settlement for the negotiated settlement of the ENMAX 2015-2017 PBR plan, the Commission observes that ENMAX's 2015-2017 PBR plan is not subject to an ECM. Therefore, the determinations made below are only applicable to the distribution utilities on the 2013-2017 PBR plans. However, for the next generation PBR plans, all distribution utilities will be on similar plans, and therefore, ENMAX's next generation PBR plan will include an ECM.

75. Decision 2012-237 approved an ROE-based ECM based on the ATCO utilities' proposal.[67] As set out in paragraph 766 of that decision, the ATCO utilities described the workings of this mechanism as follows:

> … a post PBR add-on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The "ROE bonus" would apply for 2 years after the end of the PBR Plan.[958]
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> [958] [Proceeding 566] Exhibit 98.02, ATCO Electric application, page 11-2, paragraph 238 and [Proceeding 566] Exhibit 99.01, ATCO Gas application, page 44, paragraph 129.

76. The Commission specified that the "simple average approved ROE" referenced in the quote above should be the average approved generic ROE in place during each year of the current generation PBR term.[68] In terms of the "simple average ROE achieved," the Commission determined that the distribution utilities' actual ROE calculated in the same way as the actual ROE reported in the Rule 005 filings should be used.[69]

77. In its August 21, 2015 letter, establishing the scope of this proceeding, the Commission asked parties to consider how the ECM approved in the 2013-2017 PBR plans should be incorporated into the rebasing process or next generation PBR plans.[70] The Commission did not include the continued use of the ECM or the five-year averaging parameters within the scope of this proceeding. Accordingly, subject to two clarifications on the ECM calculations discussed below, this decision is limited to a consideration of two issues. First, given that the ECM for the 2013-2017 PBR term will take the form of a ROE add-on percentage to the ROE approved for the first two years of the next generation PBR plans, it is necessary to determine the rate base or rate bases to which the approved ROE add-on will be applied. Secondly, the Commission must determine how the ECM amount will be collected during the next generation PBR term.

[65] Exhibit 20414-X0056, Brattle evidence, PDF page 23.
[66] Decision 2012-237, paragraphs 759 and 775.
[67] In Decision 2012-237, at paragraphs 775-776, the Commission approved an ECM for ATCO Electric, ATCO Gas, and EPCOR. In Decision 2013-072, at paragraph 83, the Commission approved the same ECM for AltaGas and Fortis.
[68] Decision 2012-237, paragraph 779.
[69] Decision 2012-237, paragraph 780.
[70] Exhibit 20414-X0026, AUC letter - Final issues list, August 21, 2015, attachment, Issue 1(d), PDF page 11.

Accordingly, the interveners' proposal that the ECM not be renewed for the next generation PBR plans is outside of the scope of this proceeding.[71] EPCOR's proposal to change the methodology and use a three-year average ROE rather than a five-year average, as approved in Decision 2012-237, is similarly outside the scope of this proceeding.[72]

78. Prior to addressing the principal issues of the rate base to be used in determining the ROE add-on percentage and the collection mechanics, the Commission considers that two matters relating to the ECM calculation require clarification. In this proceeding, the UCA pointed out that a verbatim read of the ECM calculation proposed by the ATCO utilities and referenced in paragraph 766 of Decision 2012-237 implies an ECM add-on equal to the 25 per cent of the difference between the average allowed and average actual ROEs, to a maximum of 0.5 percentage points.[73] The distribution utilities have all argued that the intention of the ATCO utilities' wording was to calculate the ECM add-on as a one half the difference, subject to the same maximum value.[74] The distribution utilities pointed out that the ATCO utilities' examples of an ECM calculation provided in the proceeding leading to Decision 2012-237, also provided on the record of this proceeding, reflect the ECM calculation to be 50 per cent of the difference.[75]

79. Although the ATCO utilities' proposed language allows for ambiguity in the method by which the ECM is to be calculated, the examples provided by the ATCO utilities in support of its ECM proposal clearly demonstrated the calculation. The Commission confirms that the ECM calculation required by paragraph 766 of Decision 2012-237 is to be done in accordance with the examples provided by the ATCO utilities on the record of that proceeding. Accordingly, the Commission confirms that the ECM ROE add-on calculation to be 50 per cent of the difference between the average allowed and average actual ROEs over the course of the PBR term.

80. The second issue to be clarified is whether original Rule 005 filings are to be used in calculating the average actual ROE at the end of the next generation PBR plans or if the ROE restatements discussed in Section 7 of this decision in connection with reopener applications are to be used. AltaGas, Calgary, EPCOR and the UCA submitted that if ROE restatements are included in the next generation PBR plans, restated ROEs should be used for ECM calculations, as they provide a more accurate assessment of a utility's performance.[76]

81. The Commission has determined that the original Rule 005 filings will be used for purposes of calculating the average actual ROE during the 2013-2017 PBR term. Unlike reopeners, which will be assessed annually based on a Rule 005 ROE or restated ROEs for a given year, ECM calculations are based on a five-year average ROE. Using restated ROEs in the calculation of an average for ECM purposes will likely lead to inconsistency and confusion as restated ROEs for each PBR year may be reflective of differing degrees of finality. For example, at the end of the PBR term, the Commission will likely have all the final data for 2018 and 2019, less for 2020 and 2021, and perhaps none for 2022. Further, it is not clear that the restated ROEs

71 Exhibit 20414-X0618, UCA argument, paragraphs 30-31; Exhibit 20414-X0638, CCA reply argument, paragraph 76; Exhibit 20414-X0636, Calgary reply argument, paragraph 207.

72 Exhibit 20414-X0623, EPCOR argument, paragraphs 37-38.

73 Exhibit 20414-X0618, UCA argument, paragraphs 25-27.

74 Exhibit 20414-X0622, ATCO utilities argument, paragraph 61; Exhibit 20414-X0624, Fortis argument, paragraph 54; Exhibit 20414-X0616, AltaGas argument, paragraph 96; Exhibit 20414-X0635, EPCOR reply argument, paragraph 27.

75 Exhibit 20414-X0513, undertaking response by Mr. Stock to Ms. Preda at Transcript, Volume 5, page 873.

76 Exhibit 20414-X0289, AUI-AUC-2016APR15-016; Exhibit 20414-X0238, CALGARY-AUC-2016APR15-011; Exhibit 20414-X0256, EDTI-AUC-2016APR15-032; Exhibit 20414-X0184, UCA-AUC-2016APR15-013.

for the last year of the next generation PBR term, 2022, will be available in time to apply the ECM in the following two years, 2023 and 2024. For these reasons, the Commission finds that as set out in Decision 2012-237, the distribution utilities' ROE from Rule 005 filings should be used for ECM calculations.[77]

82. As noted above, the Commission needs to determine the rate base to be used in applying the ROE add-on percentage associated with the first term's ECM. The Commission must also determine how this ECM amount will be collected during the first two years of the next generation PBR term.

83. The Commission generally agrees with the UCA's position[78] that because the ECM ROE add-on percentage is calculated based on a utility's earnings in the 2013-2017 PBR term, it should not be applied to the actual 2018 and 2019 rate base amounts, as proposed by AltaGas, the ATCO utilities and Fortis.[79] Additionally, such an approach would not promote regulatory efficiency as an ECM placeholder would need to be established, and subsequently trued up, when the final rate base amount for each of 2018 and 2019 became known. Also, as EPCOR pointed out, this approach may require the Commission to test the 2018 and 2019 rate base amounts.[80] The Commission does not agree, however, with the UCA's position that the ROE add-on percentage should be applied to the actual average rate base over the entire 2013-2017 PBR term. Such an approach does not correspond with the intention of the ECM which was to incent efficient behaviours at the end of the term. The Commission favours an ECM calculation based on the mid-year rate base during the final year of the 2013-2017 PBR term.

84. In light of these considerations, the Commission finds reasonable EPCOR's proposal to calculate the ECM amount by applying the ECM ROE add-on to the 2017 mid-year rate base and escalating the obtained ECM dollar amount by the approved next generation I-X value for each for 2018 and 2019, with subsequent true-up.[81] Consistent with the overall rebasing approach set out in sections 4.1 and 4.2, the Commission directs the distribution utilities on the 2013-2017 PBR plans to calculate the interim ECM amount by applying the ECM ROE add-on to the interim 2017 notional estimated mid-year rate base and escalating the obtained interim ECM dollar amount by the approved I-X value for each of 2018 and 2019. Following the determination of a final 2017 notional estimated mid-year rate base (reflective of the final approved 2016 and 2017 K factor amounts), the ECM add-on percentage will be determined as a final dollar amount for each qualifying distribution utility, escalated by the approved I-X value for each of 2018 and 2019.

85. With respect to the second issue, the collection mechanics for both the interim and final ECM add-on amounts, the Commission agrees with those parties that indicated the ECM dollar amounts should not be included in the going-in rates but rather collected by way of a Y factor in

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77 Decision 2012-237, paragraph 780.

78 Exhibit 20414-X0618, UCA argument, paragraph 29.

79 Exhibit 20414-X0616, AltaGas argument, paragraph 97; Exhibit 20414-X0622, ATCO utilities argument, paragraph 59; Exhibit 20414-X0624, Fortis argument, paragraphs 47.

80 Exhibit 20414-X0256, EDTI-AUC-2016APR15-008(b).

81 Exhibit 20414-X0256, EDTI-AUC-2016APR15-008(b).

each of 2018 and 2019.[82] This will avoid making additional going-in rates adjustments for 2018 and 2019 and clearly identify the ECM amount to be collected.

5 Productivity offset (X factor)

5.1 Setting the X factor

86. In its past decisions dealing with prior generations of PBR plans, the Commission expressed its preference for an approach to setting the X factor that is based on the average rate of long-term productivity growth in the industry.[83] The X factor, combined with the I factor, is designed to create incentives similar to those in competitive markets.

87. The first step in determining the X factor is to examine the underlying industry TFP growth over time, commonly determined by measuring TFP growth. The TFP growth value percentage result may then be supplemented by adjustments applicable to the utilities subject to the PBR plans, for example, a stretch factor, to arrive at a final X factor.[84] Reflecting the above approach, in Decision 2012-237, the X factor of 1.16 per cent was determined as the sum of the underlying long-term industry TFP growth value of 0.96 per cent and a stretch factor of 0.2 per cent.[85]

88. Determination of the X factor in the next generation PBR term was the second item on the final issues list established by the Commission for the current proceeding. Although the Commission decided not to sponsor a new TFP growth study, parties were free to address all aspects of the X factor for the next generation PBR plans.[86]

89. All parties to this proceeding generally agreed that, for the next generation PBR term, the X factor should be determined in the same way as previously; that is, a component based on industry TFP growth and a stretch factor. However, parties disagreed on the details of how TFP growth should be calculated, and limitations on its range, and also on the value of the stretch factor, if any, as discussed in the sections of this decision that follow. Specifically, Section 5.2 discusses the TFP growth studies, including a discussion of assumptions. The use and size of a stretch factor is discussed in Section 5.3. Section 5.4 addresses the Commission's determination on the X factor for the next generation PBR plans, and Section 5.5 addresses the X factor for ENMAX's 2015-2017 PBR plan. Finally, Section 5.6 discusses the proposals for a non-negative I-X provision.

5.2 Revised TFP growth studies

90. In Proceeding 566 leading to Decision 2012-237, the Commission engaged National Economic Research Associates (NERA) to conduct a TFP growth study. NERA's study involved analysis of the distribution component of 72 U.S. electric and combination of electric/gas utilities over the period from 1972 to 2009. Although NERA's was not the only TFP growth study

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82 Exhibit 20414-X0616, AltaGas argument, paragraph 99; Exhibit 20414-X0622, ATCO utilities argument, paragraph 59; Exhibit 20414-X0624, Fortis argument, paragraph 51; Transcript, Volume 14, page 2965, lines 10-21 (Mr. Zurek).

83 Decision 2009-035, paragraph 176; Decision 2012-237, paragraphs 277 and 288.

84 Decision 2012-237, paragraph 279.

85 Decision 2012-237, paragraphs 514-515.

86 Exhibit 20414-X0026, AUC letter – Final issues list, August 21, 2015, paragraph 34.

considered in that proceeding, the Commission found the NERA study to be preferable because of the "objectivity and transparency of the data and of the methodology used, the use of data over the longest time period available and the broad based inclusion of electric distribution utilities from the United States."[87] The final approved TFP growth value of 0.96 per cent, determined as the difference between growth in output and growth in inputs, was obtained as the average of 37 annual TFP growth values for the 1972-2009 period, where each annual value comprised a weighted average of TFP growth values for the 72 individual firms for that year, with weights based on relative firm size in terms of sales volume in megawatt hours (MWh), where these sales were also used as the output measure for the distribution utilities.

91. Three TFP growth studies were provided in this proceeding: (i) a study undertaken by Dr. Brown and Dr. Carpenter of Brattle for the distribution utilities other than EPCOR (Brattle study);[88] (ii) a study undertaken by Dr. Meitzen of Christensen Associates for EPCOR (Meitzen study);[89] and (iii) a study undertaken by Dr. Lowry of PEG for the CCA (Lowry study).[90] Dr. Pavlovic et al. of PCMG filed reply evidence for the UCA, where they criticized a number of aspects of the NERA TFP methodology used in the Brattle and Meitzen studies but did not provide a TFP growth recommendation.[91]

92. Both Brattle and Dr. Meitzen described their approach as extending or updating the NERA study analysis for five more years, 2010 to 2014.[92] Both the Brattle study and the Meitzen study updated the NERA study by including data from 2010-2014 period and also made certain refinements to the NERA study. In contrast, the Lowry study "uses alternative methods and is more customized to special operating conditions in Alberta."[93] Although the Lowry study relied on the same general index approach used by NERA for calculating the TFP growth number,[94] there were a number of important differences in approach. Among other differences, the Lowry study used a different output measure (number of customers instead of MWh volumes), a shorter data period (1997-2014), a different and larger set of firms (88 instead of the 72 in the NERA study, although the Lowry study also considers smaller subsets of the 88 firms), a different method for aggregating across firms (unweighted instead of weighted), output data combined from two sources (FERC Form 1, as used in the NERA, Brattle and Meitzen studies, and EIA Form 861),[95] and some different assumptions underlying the determination of the input growth index. In addition, the Lowry study was produced using computer code and proprietary computer software rather than spreadsheets as used in the NERA, Brattle and Meitzen studies.

93. A summary of the TFP growth findings, including recommendations, from the three studies filed in this proceeding, as well as from the NERA study filed in the PBR Proceeding 566 (NERA 2012), are shown in Table 1. In each case, the TFP growth values are averages of all the annual values in the specified time period, although for the Meitzen study, the recommendation

87 Decision 2012-237, paragraph 411.
88 Exhibit 20414-X0056, Brattle evidence, Section III, pages 23-38.
89 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, PDF pages 185-244.
90 Exhibit 20414-X0082, CCA evidence of Dr. Lowry, Section 4, pages 42-73.
91 Exhibit 20414-X0403, UCA reply evidence of K. Pavlovic, M. Griffing and D. Mugrace.
92 Exhibit 20414-X0056, PDF pages 27-28 (Brattle), and Exhibit 20414-X0074, PDF pages 202-204 (Meitzen).
93 Exhibit 20414-X0082, page 57.
94 The Lowry study refers to multifactor productivity (MFP) rather than TFP, to reflect the use of multiple inputs, but this is principally an issue of nomenclature.
95 Specific data sources are U.S. Federal Energy Regulatory Commission (FERC), Form 1: Electric Utility Annual Report, and U.S. Energy Information Administration (EIA), Form 861: Electric power sales, revenue, and energy efficiency.

is to use the average of two averages, one based on all the annual values in the last 15 years and one based on all the annual values in the last 10 years. As this table shows, the Brattle and Meitzen studies yield similar TFP growth value estimates, with differences mainly attributable to the different data periods used.[96] The table also shows there is a considerable difference in TFP growth calculated in the Lowry study when compared to the results of the Brattle and Meitzen studies. Similarly, TFP growth is almost twice as large in the Lowry sample when a smaller selected sample of the 88 firms is used in the calculation when compared to the full sample. This sample size issue is addressed in Section 5.2.2 below. Finally, differences between initial and final TFP growth calculations reflect corrections made in reply evidence as the result of self-identified errors and/or accepted improvements suggested by other parties.

Table 1. TFP growth study findings

Study	Output measure	Recommended data period	Number of firms	TFP growth calculation	
				Initial	Final
NERA 2012	Volume (MWh)	1972-2009	72	-	0.96
Brattle	Volume (MWh)	2000-2014	67	-0.89%	-0.79%
Meitzen	Volume (MWh)	Average of last 15 (2000-2014) and last 10 (2005-2014) years	68-72	-1.11% [Note 1]	-1.11% [Note 1]
Lowry	Number of customers	1997-2014	88 21	+0.48% +0.80%	+0.43% +0.78%

Note 1: As per Exhibit 20414-X0074, paragraph 95, clarified in Exhibit 20414-X0623, paragraph 55, EPCOR and Dr. Meitzen recommended a methodology for calculating TFP growth rather than a specific value, with the numerical value to be decided using a new TFP growth study that utilizes the latest available data before the next generation PBR term begins.

Source: Brattle study initial TFP growth: Exhibit 20414-X0056, PDF pages 36-37, final TFP growth: Exhibit 20414-X0387, PDF pages 21-22; Meitzen study, initial TFP growth (71 firms): Exhibit 20414-X0074, PDF page 225, (67 firms): Exhibit 20414-X0256, EDTI-AUC-2016APR15-010, Table 3, PDF page 41; Lowry study initial TFP growth: Exhibit 20414-X0082, Table 5a on page 64 (88 firms), Table 5c on page 68 (21 firms), final TFP growth: Exhibit 20414-X0468, PDF pages 40, 42.

94. The three studies filed in this proceeding provide a relatively wide range of TFP growth values, with all final recommendations smaller than, and in some cases much smaller than, the TFP growth number adopted by the Commission in Decision 2012-237. The issue that the Commission must address, therefore, assuming the Commission finds any of the studies to be acceptable, is not whether the TFP growth component of 0.96 per cent adopted in Decision 2012-237, needs to be lowered for the next generation PBR plans, but rather the extent to which it needs to be lowered. In order to address this issue, the Commission must evaluate the applicability of the various TFP growth values provided by the expert evidence in this proceeding. The Commission’s considerations are provided in the following sections 5.2.1 to 5.2.5. Specifically, Section 5.2.1 deals with the objectivity, consistency and transparency of the three studies in this proceeding. Section 5.2.2 focuses on which firms were included in the studies. Section 5.2.3 addresses differences in study calculation methods and assumptions pertaining primarily to growth of inputs. Section 5.2.4 deals with the output measures. Finally, time period considerations are set out in Section 5.2.5.

5.2.1 Objectivity, consistency and transparency of TFP growth studies

95. This section focuses on some of the elements of TFP growth studies that were considered to be of importance in Decision 2012-237. They include objectivity, consistency and

[96] For example, as per Exhibit 20414-X0256: EDTI-AUC-2016APR15-010, PDF page 41, the Meitzen study growth estimate for the same 67 firms as in the Brattle study sample, using just the last 15 years (2000-2014), is -0.81 per cent.

transparency.[97] Satisfaction of these conditions by any particular study does not contribute to a determination of the magnitude of an X value, but it does help the Commission decide if the numbers from that study are even worthy of consideration given the regulatory context in which they are presented. In Decision 2012-237, the NERA study was found to satisfy these requirements,[98] and since the Brattle and Meitzen studies in the current proceeding use the same methodology but update the NERA analysis to include additional years of data from the same publically available data sources, they also satisfy them.

96. The distribution utilities submitted that caution should be exercised when relying on the results of the Lowry study because of the same lack of objectivity, consistency and transparency that the Commission identified with respect to his work in Decision 2012-237.[99] Specifically, while the Lowry study in this proceeding relied on publicly available data, the distribution utilities stated that these TFP results were obtained using a software package that is not widely used, rather than spreadsheets, and that the underlying calculations and assumptions were not documented or clearly explained.[100] The distribution utilities also expressed concerns with the potential lack of objectivity and consistency in the Lowry study, based on their observation that "PEG's TFP results vary considerably from study to study, even though the input data and the study time period were exactly the same."[101]

97. Dr. Lowry responded that the employed software is used "for all of our [PEG's] projects since the inception of the company" and is available for purchase.[102] Dr. Lowry defended performing the TFP growth calculation using computer code because it is "easier to review and validate than the array of spreadsheets."[103] Dr. Lowry also expressed his view that he provided at least the same level of information, if not more, as NERA in the last proceeding and experts replicating NERA's study in this proceeding.[104] Further, the CCA submitted that additional information or explanation was available should it be needed and requested.

98. The Commission does not view the use of computer code and proprietary software in and of itself as limiting the transparency of a study, particularly if the analysis can be reproduced in a spreadsheet format with intact formulas and assumptions provided. In the future, the Commission would prefer such analysis to also be reproduced using spreadsheets when, as in this situation, it is possible to do so.[105] The Commission considers that the present proceeding provided sufficient opportunity for all parties, and the Commission, to explore the basis of Dr. Lowry's calculations and assumptions that were put forward in his direct evidence through IRs and cross-examination.

97 Decision 2012-237, paragraph 353.
98 Decision 2012-237, paragraph 353.
99 Decision 2012-237, paragraph 364.
100 Exhibit 20414-X0619, ENMAX argument, paragraphs 47-50; Exhibit 20414-X0623, EPCOR argument, paragraphs 71-73.
101 Exhibit 20414-X0634, ENMAX reply argument, paragraph 23; Exhibit 20414-X0635, EPCOR reply argument, paragraph 33. The other studies referred to were provided in other proceedings and/or jurisdictions.
102 Transcript, Volume 12, page 2422, lines 2-3 (Dr. Lowry) and Exhibit 20414-X0203 CCA-EDTI-2016APR15-001(s).
103 Exhibit 20414-X0203 CCA-EDTI-2016APR15-001(t).
104 Transcript, Volume 12, pages 2425-2426 (Dr. Lowry).
105 The PEG study data were provided in spreadsheet form in Exhibit 20414-X0100, with variable definitions in Exhibit 20414-X0106. These data were used by Dr. Meitzen in an attempt to reproduce the PEG study results using a spreadsheet in Exhibit 20414-X0417. The replication results obtained by Dr. Meitzen, for input, output, and TFP (MFP) growth, are almost identical to those in Table 5a of the PEG study, Exhibit 20414-X0082, page 64.

99. An additional issue considered by the Commission was the "customization" undertaken in the Lowry study. The CCA stated that "Dr. Lowry customizes his results to the application," which, in the CCA's view, "enhances the methodology."[106] Customization of TFP growth studies introduces a level of subjectivity that may obscure the objectivity and transparency of the TFP growth value that would result without the customization, unless the results are provided both with and without any added customizations. The Lowry study provided TFP growth results, as well as the input and output growth components of TFP growth, for each sample year, for both the full sample of 88 firms and for specific customized subsamples. Consequently, for the purposes of the present proceeding, the Commission will not reject, or attach less weight to, the Lowry study presented in his primary evidence on the grounds of lack of objectivity, consistency, and/or transparency.

5.2.2 Sample of comparative firms in the TFP growth study

100. This section focuses on the particular firms included in the various TFP growth studies. One issue here pertains to input data modifications arising from firm mergers, asset transfers, etc., while another concerns whether analysis that utilizes data from a subset of the available firms, rather than from all available firms, should be afforded lesser, equal, or preferential treatment. As shown in Table 1, TFP growth values from analysis that utilizes subsets of firms selected in the Lowry study are much higher than TFP growth values in the same study that utilizes all firms. Consequently, determination of this issue concerning subsets of firms may affect the range of possible values that the Commission considers for the TFP growth component of the X factor.

101. The NERA study in the PBR Proceeding 566 included 72 firms for which data were available for the full sample period from 1972 to 2009, with certain data series for capital additions and retirements reaching back to 1964. The Brattle study updated the NERA study to 2014; however, in doing so, it discarded the 2010-2014 data for five firms due to issues with missing or inconsistent data; for example, due to mergers.[107] In updating the NERA study, the Meitzen study did not check for inconsistent data,[108] and discarded four utilities for years 2010-2014 for which data were unavailable.[109]

102. While both Brattle and Dr. Meitzen excluded data for years 2010-2014 for the discarded utilities, they retained these data in the 1972-2009 calculation, resulting in an unbalanced panel (i.e., a different number of utilities, between 67 and 72, was used in the calculation in different years). In its reply evidence update, Brattle excluded the five utilities for all of the sample years; this did not have a significant effect on the resulting TFP growth value. Dr. Meitzen retained his original recommendation. However, in response to Commission IRs and follow-up calculations, some of Dr. Meitzen's calculations were undertaken using the 67 firms in the Brattle sample. As shown in this response, using an unbalanced panel in Dr. Meitzen's case did not appear to have a significant effect on the resulting TFP growth calculation.[110]

103. In the case of the NERA study and, therefore, the Brattle and Meitzen studies, as well as the Lowry study, their respective samples included all firms for which data of sufficient quality

[106] Exhibit 20414-X0630, CCA revised argument, paragraph 197.
[107] Exhibit 20414-X0056, Brattle evidence, page 26, Q/A 52.
[108] Transcript, Volume 13, pages 2646-2647 (Dr. Meitzen).
[109] Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, paragraph 36.
[110] Exhibit 20414-X0256, EDTI-AUC-2016APR15-010(a).

were available.[111] With regard to the input measure, Dr. Lowry indicated that NERA and, therefore, the Brattle and Meitzen studies, did not account for cost transfers due to mergers, divestitures, or transfers of assets between transmission and distribution. These input data changes affected some dozen firms.[112] However, Brattle indicated that, after accounting for these data changes, the results were within 0.1 percentage points of the original value for both the Brattle and Lowry studies.[113]

104. Consistent with the findings in Section 5.2.4, which deals with the output measure, the Commission is of the view that while modification (correction, patching, or deletion) of particular components of input data series can be useful in certain circumstances, the procedures and the criteria used to determine such modifications, and when and where they are to be applied, needs to be documented carefully, with supporting reasoning. A lack of such detailed documentation and support must be taken into consideration when evaluating analysis that relies on these data, in exactly the same way that would apply to evaluating analysis that utilizes raw (unverified) data that has not been examined, and if necessary adjusted, with reasoning and documentation provided, for the presence of anomalies. In the present circumstances, since the effect of the modifications is minimal, the Commission will not weight the studies differently due to the use or non-use of these input data modifications.

105. The Lowry study includes 88 firms in the full sample, and smaller subsets of these firms in some additional TFP growth calculations. The CCA contended that because the Lowry 88 firm study "involves a substantially larger sample of utilities than the Brattle or Meitzen studies," it may be viewed as better representing the power distribution industry.[114] However, the Lowry study data only extends from 1997, and it is unclear whether all 88 firms could have been included in this study if the longer data period available in the NERA, Brattle and Meitzen studies had been included. On this basis, the Commission does not attribute less weight to the Meitzen and Brattle studies due to their smaller sample sizes.

106. The Lowry study considers several subsets of the 88 firms in the full sample, on the basis that these are likely to be more representative of conditions faced in Alberta. Specifically, the "rapid-growth" subsample comprises those 21 utilities "which experienced customer growth during the full sample period which was similar to the brisk growth which Alberta distributors are likely to experience during the indexing years of the next generation PBR plans,"[115] while the "Mountain West" subsample is similar to Alberta geographically, comprising "ten utilities with service territories in the Pacific Northwest and intermountain West."[116]

107. In their evidence for the UCA, Dr. Pavlovic et al. expressed their view that the "actual range of possible productivity improvements for electric utilities, however, are in fact restricted by the specific circumstances of electric utilities – geography, meteorology, organizational structure, and regulatory scrutiny." Therefore, consistent with the Lowry study approach, the UCA witnesses advocated looking "at the results for subsets of the entire population for evidence

111 Decision 2012-237, paragraph 322; Exhibit 20414-X0056, Brattle evidence, page 26, Q/A 52; Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, paragraph 36; Exhibit 20414-X0082, CCA evidence of Dr. Lowry, page 59.

112 Exhibit 20414-X0468, PEG reply evidence for the CCA, pages 8-11.

113 Exhibit 20414-X0387, Brattle reply evidence, Table 6 on 36.

114 Exhibit 20414-X0630, CCA revised argument, paragraph 160.

115 Exhibit 20414-X0082, PDF page 70.

116 Exhibit 20414-X0082, PDF page 71.

that individual differences in circumstances actually affect productivity in either the short- or the long-term."[117]

108. In the judgement of the Commission, the issue of whether the TFP growth value should be determined based on a customization or tailoring of firms selected to be included within the TFP growth study based on characteristics similar to the Alberta distribution utilities is directly related to the underlying objectives of a PBR plan.

109. In Proceeding 566, the Commission determined that a key reason for implementing PBR for the distribution utilities in Alberta was a desire to ensure that the decision making and outcomes achieved by regulated distribution utilities emulated, to the extent possible, the decision making and outcomes that would have arisen had decision makers in those firms been subject to the incentives found in competitive markets.

110. Dr. Lowry, in his evidence, indicated that productivity trends are influenced by such things as business conditions that "may be unusual in Alberta …"[118]

111. Commission counsel, Ms. Wall, then explored other differences that could affect TFP growth, in this case between Alberta and U.S. utilities:[119]

> Q. Okay. Now, I think you would agree there's many possible differences between Alberta and the utilities in the US sample; right? It could be size, service territory, customer density, peak demands, climate, average asset age, all kinds of things; right?
> A. Yes.

112. The Commission considers that this answer is not restricted to utilities on different sides of the border. It would apply equally to a comparison of individual Alberta utilities, and indeed to a comparison of individual U.S. utilities.

113. In Dr. Meitzen's view, Dr. Lowry's approach used in his subset analysis was akin to "cherry-picking," which he did not support.[120] Brattle also did not support this approach, commenting as follows:[121]

> There are many ways in which one utility may differ from another (for example, service territory size, customer density, customers per line mile, peak demand, average load factor, penetration of distributed solar photovoltaic, various dimensions of climate, average asset age and so on). In our view it is not possible to disentangle the parameters which may be relevant for determining the scope for productivity improvement from those which are not relevant.

114. Based on this evidence, the Commission considers that, in general, it is likely that in competitive markets, there is a variety of factors that influence the ability of firms operating in that market to achieve TFP gains. Since the design of the PBR plan for Alberta is meant to emulate these aspects of competitive markets, this suggests that it is preferable to use broad samples that will embody variation in more of the characteristics that influence productivity, as

117 Exhibit 20414-X0403, UCA reply evidence of Dr. Pavlovic et al., page 10, Q/A 24.
118 Exhibit 20414-X0468, CCA reply evidence of Dr. Lowry, page 35.
119 Transcript, Volume 12, page 2359, line 21 to page 2360, line 1 (Dr. Lowry).
120 Exhibit 20414-X0412, EPCOR reply evidence of Dr. Meitzen, pages 18-19, Q/A 25.
121 Exhibit 20414-X0387, Brattle reply evidence, page 29, Q/A 60.

would be found in a competitive market. Accordingly, although the Commission considers that subsamples selected on a single criterion can provide useful information, analysis using the full sample, or possibly subsamples selected on multiple criteria, will better inform the Commission's judgement as to the possible range of TFP growth values that are reflective of competitive markets. For this reason, although the Commission will refer to the subset analysis as indicative of possible difficulties in the measurement of TFP growth, subsequent attention to the Lowry study is limited to its TFP growth findings for its full sample of 88 firms.[122]

115. This decision, to focus on the Lowry study's full sample rather than results for various subsamples, informs the Commission's decision making concerning the extent to which the TFP growth component of the current X factor, 0.96 per cent, needs to be reduced for the next generation PBR plans. As shown in Table 1, the highest TFP growth values were obtained from the Lowry study subsample, so that focusing on the full sample in the Lowry study suggests a downward adjustment to the TFP growth component compared to its previous value. Of course, as discussed in the following sections, there is considerable variability associated with this TFP growth component, due to the different assumptions that are made, and accounting for this variability means that this TFP growth component is not necessarily prevented from exceeding the highest remaining recommendation (Table 1) of +0.43.

5.2.3 Assumptions pertaining to measuring input growth and study calculation methods

116. This section considers the different assumptions underlying the determination of input growth in the various TFP growth studies, as well as differences in calculation methods, and their effect on the resulting TFP growth values. Consideration of these issues helps inform the Commission about the range of reasonable values that the TFP growth component of the X factor and how sensitive this range is to variations arising from the assumptions employed.

117. Both Dr. Meitzen's and Brattle's studies adopted the NERA methods to calculate TFP growth. As well, those studies relied on NERA's assumptions pertaining to measuring input growth, with one main correction identified by Dr. Meitzen that relates to the measurement of labour input.[123] Dr. Lowry took issue with the assumptions used by NERA, and in his study used different calculation methods as well as different input growth assumptions.

118. More specifically, the differences in the calculation methods pertained to the use of the chain-weighted index in the Lowry study, while the NERA-based studies relied on the multilateral index.[124] As well, NERA's TFP calculations put more weight on larger utilities, whereas the Lowry study averages growth rates across firms in any year, thereby weighting firms equally. The assumptions pertaining to measuring input growth included among others, the depreciation method (one hoss shay, geometric decay or a straight line method), the use of net rather than gross plant in the benchmark year of the TFP growth study, the asset service life, and the choice of price indexes used in calculating such input quantities as labour, materials and

122 In some subsequent analysis, attention is focused on utilities that are common to both the Lowry, Brattle and Meitzen studies, but unlike the Lowry study subsamples, this selection is not based on the utilities all satisfying a particular criterion pertaining to one of their characteristics.

123 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, paragraph 39. In its reply evidence, Exhibit 20414-X0387, page 19, Q/A 39, Brattle has adopted this correction.

124 See Transcript Volume 11, pages 2280-2281 (Dr. Lowry), and Volume 13, pages 2648-2649 (Dr. Meitzen), for a discussion of the differences between and applicability of these two types of indexes, as well as the conclusion that, in the studies in evidence here, the choice had very little effect on the results.

services. In addition, while NERA-based studies include only costs labelled as "distribution" in FERC Form 1 accounts, the Lowry study includes a wider range of cost categories by allocating some expenses and wages related to customer accounts, administrative and general, and some general plant.

119. These issues were for the most part, debated in the PBR Proceeding 566 and in Decision 2012-237, the Commission noted that "Some of these issues reflect an ongoing academic debate on which consensus has not been reached, or for which there is no right or wrong answer."[125] As a result, and contrary to EPCOR's view in this proceeding,[126] in Decision 2012-237, the Commission did not explicitly reject the different assumptions used by different parties. Along the same vein, Drs. Brown and Carpenter were generally neutral about the particular assumptions that were adopted, referring to the debate about the various methodologies as being "within the range of statistical precision of a TFP study,"[127] whereas Dr. Meitzen[128] and Dr. Lowry[129] were more adamant that the assumptions each of them had adopted were to be preferred.

120. In the Commission's view, there is no overwhelming new evidence in this proceeding that any of these particular assumptions are correct or incorrect. The assumptions chosen reflect the practitioner's decisions and beliefs based on the available choices that can be applied to the data, and there is generally no test presented in evidence that can be applied to determine which assumptions are more applicable to particular data or the purposes for which it is used. It is unlikely that any group of unassociated practitioners will make the same choices for all the assumptions, even with the same universe of data series available to them.[130] For this aspect of the analysis, the Commission is, therefore, unwilling to specify a preference for the set of assumptions used by any particular one of the three TFP growth studies.

121. Nevertheless, the studies provide the Commission with important information about the sensitivity of the TFP growth measures to combinations of input measurement assumptions used in the different studies. For example, the Lowry study notes that Alberta power distributors are small by U.S. standards, and for this reason contends that calculating industry TFP growth as a simple average across all firms rather than a weighted average (using firm's share of total volume in the year in question, as is done in NERA-based studies) is more relevant.[131] However, in his testimony Dr. Lowry noted that it would not affect the results greatly.[132] In testimony, Dr. Brown stated that either the weighted or unweighted index can be meaningful.[133] Using the same 53 firms that are common to both the Brattle and Lowry studies, weighted versus unweighted output growth (volume) changed from 0.87 to 0.72 per cent for 1997-2014, and from 0.64 to 0.47 per cent for 2000-2014, indicating a drop of between 0.15 and 0.17 percentage

125 Decision 2012-237, paragraph 413.
126 In its argument, Exhibit 20414-X0623, at paragraph 77, pages 29-31, and especially at footnotes 179 and 195, EPCOR interpreted that paragraph 413 of Decision 2012-237 constitutes a rejection of similar assumptions by Dr. Lowry in Proceeding 566.
127 Transcript, Volume 1, page 167, lines 13-14, following the discussion on pages 161-167. (Drs. Carpenter and Brown).
128 Transcript, Volume 14, page 2792, line 13 to page 2793 line 4 (Dr. Meitzen).
129 PEG, in its reply evidence, Exhibit 20414-X0468, classified NERA's choice of assumptions as either "serious," "obvious methodological and data errors" (page 4), or "substandard practices" (page 17).
130 Other practitioners may also make different choices for assumptions other than those that were raised here, including aspects of sample design.
131 Exhibit 20414-X0468, PDF page 35.
132 Transcript, Volume 11, pages 2282-2284 (Dr. Lowry).
133 Transcript, Volume 2, pages 342-345 (Dr. Brown).

points.[134] For inputs, removing the unequal weighting for these same 53 firms changed input growth from 1.31 to 1.22 per cent for 1997-2014, a drop of 0.09 percentage points, and from 1.36 to 1.33 per cent for the years 2000 to 2014, a drop of 0.03 percentage points.[135]

122. By way of another example, based on the evidence in this proceeding, the inclusion of some of the shared costs not labelled as "distribution" in FERC Form 1 in the TFP growth calculation remains a contested issue, and depends on the practitioner's decisions and beliefs. While Dr. Lowry for the CCA, and Dr. Pavlovic for the UCA, advocated including these costs using what they considered to be adequate allocation methodologies,[136] Brattle and Dr. Meitzen argued against such a procedure because there is no unique or universally accepted method to allocate joint and common costs and, therefore, the "judgement inherent in allocating common costs can invite controversy."[137] In addition, Dr. Meitzen indicated that if one assumes that shared costs grow at the same rate as other costs irrespective of their absolute quantity, there is no need to allocate those costs when calculating growth rates.[138]

123. The Commission notes, however, that different choices of assumptions that underpin the calculation of the growth rates of inputs do have noticeably different effects on the resulting growth rate of inputs, and hence on TFP growth. In his reply evidence, Dr. Meitzen shows that for the 1997-2014 period, input growth rate in the Lowry study is 0.42 per cent for the full sample of 88 firms, while the Meitzen and Brattle studies have input growth rates of 1.39 per cent and 1.48 per cent, respectively.[139] However, these different growth rates are not just due to different input assumptions, as they are also affected by differences in the firms that are included in the samples and in methods of aggregation across these firms. Controlling for these differences to enable an apples-to-apples comparison, by limiting the sample of firms just to those 53 that appear in both the Brattle and Lowry study samples, and aggregating across firms by averaging rather than using a weighted average, yields input growth rates of 0.41 per cent (Lowry study) and 1.22 per cent (Brattle study) for 1997-2014.[140] This difference of some 0.80

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[134] Commission staff calculations. Values are based on data in the Brattle study spreadsheet provided in Exhibit 20414-X0396. Firms that are not common to the two studies are deleted, as described in footnote 140. To obtain the unweighted values, output growth rates for each firm and year prior to the inclusion of the weighting factor, as provided in the spreadsheet, are averaged across the common set of firms for each year.

[135] See footnote134. An undertaking by Brattle, exhibits 20414-X0562, 20414-X0563, shows the effect of removing the weighting on TFP to be a reduction of 0.15 percentage points (from -0.79 per cent to -0.94 per cent) for their sample of 67 firms for 2000-2014, but does not show the separate effects of removing the weighting for input growth and output growth.

[136] Transcript, Volume 12, pages 2431-2432 (Dr. Lowry), and Transcript, Volume 17, pages 3556 and 3564-3568 (Dr. Pavlovic).

[137] Exhibit 20414-X0387, Brattle reply evidence, pages 40-41, Q/A 78 and 79; Exhibit 20414-X0412, EPCOR reply evidence of Dr. Meitzen, pages 15-16, Q/A 22; Lawrence Kaufmann, Mark Meitzen, and Mark Newton Lowry, "Controlling for Cross Subsidization in Electric Utility Regulation," *Edison Electric Institute*, September 1998, p. 13 as referenced in Exhibit 20414-X0412, EPCOR reply evidence of Dr. Meitzen, page 16, Q/A 22.

[138] Transcript, Volume 14, page 2819, lines 3-16 (Dr. Meitzen).

[139] Exhibit 20414-X0412, EPCOR reply evidence of Dr. Meitzen, Table 3 on page 11.

[140] Commission staff calculation of the Lowry study value is based on Dr. Meitzen's spreadsheet replication of the Lowry study, Exhibit 20414-X0417, which uses the Lowry study's firm and data list from Exhibit 20414-X0100. The firms and data used in the Brattle TFP update calculation are provided in Exhibit 20414-X0396. A comparison of these two spreadsheets identifies the firms in common to both, and data pertaining to other firms are simply deleted from the two spreadsheets. To obtain the Brattle study value, TFP growth rates for each firm and year prior to the inclusion of the weighting factor, provided in Exhibit 20414-X0396, are averaged across the common set of firms for each year. Brattle also attempted a comparison of the Lowry and Brattle

percentage points translates directly into differences in TFP growth rates, since the latter are defined as output growth less input growth, indicating that different input assumptions are a large contributor to the different TFP growth rates observed in Table 1. Brattle and Dr. Meitzen came to the same conclusion.[141]

124. Based on the evidence provided, the Commission observes that the combination of assumptions underlying the determination of input growth measurement used in the Brattle and Meitzen studies results in lower TFP growth values than the combination of assumptions underlying the determination of input growth measurement used in the Lowry study. The Commission's findings in respect of the variability in TFP growth rates, resulting from differences in assumptions pertaining to measuring input growth and study calculation methods, follows the discussion of other relevant factors such as the use of various output measures and time periods used in the TFP growth studies and can be found in Section 5.4 below.

5.2.4 Output measure

125. Another major difference among the TFP growth studies concerns the output measure. This section considers different choices for the output measure, and the effect of such choices on the resulting TFP growth values. Consideration of this issue also helps to inform the Commission about the range of values that the TFP growth component of the X factor can take, and how sensitive this range is to different sets of assumptions.

126. Considerable debate over whether a volumetric measure, number of customers, or some combination of the two would be a better output measure occurred in the PBR Proceeding 566, with the Commission recognizing in Decision 2012-237 a volumetric measure, MWh sold, to be "an acceptable measure for calculating TFP growth for electric distribution companies."[142] In that decision, the Commission also agreed that for revenue-per-customer cap plans, such as are in place for gas distribution utilities in Alberta, "the number of customers, rather than a volumetric output measure, is the correct output measure for a TFP study,"[143] but no adjustment was made to the NERA study's volumetric-based TFP growth estimate for gas distribution utilities due to "the absence of a reliable and transparent TFP study on the gas distribution industry and information on how changes in the relevant output measures and input measures for electric and gas distribution industries compare to each other over the 1972 to 2009 study period."[144]

127. NERA emphasized in the PBR Proceeding 566 that its practice is to use sales volume as an output measure.[145] This practice was adopted by the Brattle and Meitzen studies, which followed NERA's methodology.

128. Dr. Pavlovic et al. objected to the use of the MWh volumetric output measure because "there is virtually no [causal] relationship between the operations and costs of an electric distribution system and the annual volume of electricity actually delivered through the

studies using a common sample, exhibits 20414-X0387 and 20414-X0388, Table 6, but focused just on the TFP growth measures rather than input growth measures.

141 Exhibit 20414-X0387, Brattle reply evidence, page 43, Q/A 84; Exhibit 20414-X0412, EPCOR reply evidence of Dr. Meitzen, pages 6 and 11-12.

142 Decision 2012-237, paragraph 397.

143 Decision 2012-237, paragraph 394.

144 Decision 2012-237, paragraph 416.

145 Decision 2012-237, paragraph 380.

distribution system."[146] Dr. Pavlovic expressed his view that "the proper measures of output for a distribution operation are customers, customers served, and peak capacity."[147] In explaining his position at the hearing,[148] Dr. Pavlovic discussed the "Electric Utility Cost Allocation Manual" published by the National Association of Regulatory Utility Commissioners, [149] in support of his position. Reasons for his position, linking customers as an output measure and cost drivers and cost allocations for electric distribution utilities, were not fully explained.

129. The Lowry study uses number of customers as the output measure for a number of reasons, including its applicability with a revenue-per-customer cap. Dr. Lowry also pointed to the use of econometric modelling that shows the number of customers to be a more important driver of the costs of energy distributors than delivery volumes. An additional reason is that the number of customers is much more stable (that is, less variable) than the trend in delivery volumes.[150] The Commission does not find these reasons to be particularly persuasive in terms of attaching higher weight to studies that use the number of customers as the output variable rather than a volumetric measure. First, only gas distribution utilities will be under a revenue cap plan in the next generation PBR plans (electric distribution utilities remain under a price cap) and, in any event, as Dr. Carpenter[151] and Dr. Meitzen pointed out,[152] what is more relevant is the type of index that applies to the U.S. electric distribution firms in the sample, an issue on which no evidence has been adduced. Second, the evidence provided was insufficient to explain why, finding that the number of customers is a more important driver of the costs of energy distributors than delivery volumes, means that the number of customers is a better measure of output than delivery volumes. Finally, while a lack of variability of an output measure appears to have some advantages in terms of ease of numerical calculation and updating, expert evidence was not provided as to why in and of itself, this characteristic is particularly desirable in terms of deciding which output measure is more relevant.

130. In this context, the Commission acknowledges that with the prevalence of both fixed and variable revenue components for distribution utilities, the number of customers is a relevant output measure along with volume, where the relative weights assigned to these two output measures would ideally reflect the proportion of revenues generated through fixed versus variable (volumetric) charges.[153] In the absence of such information for the firms in the U.S. sample, the Commission is not prepared to discount TFP growth studies developed using either volume or number of customers as the output measure simply because of the particular output measure that was chosen, but in future would prefer sensitivity analysis that demonstrates the effect on output growth, and hence TFP growth, of varying the relative weights that are assigned to each of these two output measures.

131. The average annual growth rates associated with the number of customers output measure for 1997-2014 were 0.90 per cent for the Lowry study using the full sample,[154] and 0.86 per cent when Dr. Meitzen redid his analysis using this output measure with the 67 firm Brattle sample

146 Exhibit 20414-X0403, UCA reply evidence of Dr. Pavlovic et al., page 6, Q/A 14.
147 Transcript, Volume 17, page 3569, lines 6-8 (Dr. Pavlovic).
148 Transcript, Volume 17, page 3632, line 1 to page 3632, line 18.
149 UCA reply evidence in Exhibit 20414-X0403, PDF page 8.
150 Exhibit 20414-X0630, PDF pages 40-42.
151 Transcript, Volume 2, page 406, line 11 to page 407, line 3 (Dr. Carpenter).
152 Exhibit 20414-X0256, EDTI-AUC-2016APR15-013(f).
153 Exhibit 20414-X0173, BRATTLE-AUC-2016APR15-009(b); Exhibit 20414-X0256, EDTI-AUC-2016APR15-013(e); Exhibit 20414-X0321, CCA-AUC-2016APR15-009(d).
154 Exhibit 20414-X0468, PDF pages 40, 42.

for 2000-2014.[155] For volume, the average annual growth rates were 0.51 per cent for the Brattle study and 0.50 per cent for the Meitzen study, using the last 15 years and the Brattle sample of firms in both cases.[156] These growth rates are not all directly comparable, however, for the same reasons identified previously when comparing the results of the different assumptions pertaining to inputs; namely, differences in the firms included in the samples, in the method of aggregating across firms and, additionally, in this case, in the data period and data sources used. Using the 53 firms that are common to the Brattle and Lowry studies, growth in the number of customers is 0.88 per cent for 2000-2014.[157] Volume growth for these same firms in this same period is 0.64 per cent using the weighted average approach in the Brattle study, or 0.47 per cent if all firms are weighted equally.[158] Therefore, after controlling for differences between the studies, the difference in output measures, number of customers versus volume, affects annual growth by between 0.24 and 0.41 percentage points for this period, a number that translates directly into TFP growth differences since TFP growth is output growth less input growth.

132. A further issue with the output data concerns the source for the customer count data. Most of these data are taken from FERC Form 1, but the Lowry study combines output data from FERC Form 1 and EIA Form 861, as described previously.[159] Specifically, for a majority of firms, the Lowry study uses Form 1 data until 2000 and then Form 861 data thereafter. However, for some firms the Lowry study uses Form 1 data throughout while in others it uses Form 861 data throughout, even though for almost 35 per cent of the 88 firms the two data series are identical in all years, and for a further 30 per cent there are only a few minor differences between the two series for any particular firm in some years.[160] Some parties viewed this patching of data as problematic,[161] but patching data in this way can avoid obvious transcription errors in the original data. However, here there are anomalies that remain even in the patched data.[162]

133. While the patching of data can be useful in certain circumstances, the Commission considers that the patching procedure and the criteria used to determine which data series to use in which circumstances – that is, what and when to patch – needs to be documented carefully, with supporting reasoning. A lack of such detailed documentation and support must be taken into consideration when evaluating analysis that relies on the patched data, in exactly the same way

155 Exhibit 20414-X0256, EDTI-AUC-2016APR15-013(g), table on PDF page 50. Part of this difference arises because Dr. Meitzen calculates annual growth for the aggregated number of customers across all firms, whereas the Lowry study calculates annual growth separately for each firm and then averages these measures across firms.

156 Exhibit 20414-X0396 (Brattle); Exhibit 20414-X0256, PDF page 41 (Meitzen).

157 Exhibit 20414-X0417, spreadsheet replication of Lowry study by Dr. Meitzen using the patched customer count data utilized by Dr. Lowry, as described subsequently. Firms that are not common to the two studies are deleted, as described in footnote 140.

158 See footnote 140.

159 See footnote 95.

160 The two sets of customer count data are provided in Exhibit 20414-X0100, in columns “AA” (Form 1) and “BD” (Form 861), and are reproduced in the Meitzen spreadsheet replication of the Lowry study, in Exhibit 20414-X0417, tab “Query1,” with these same labelled columns and with the patched series used in the Lowry study in column “DF.”

161 Transcript, Volume 14, page 2845, line 5 to page 2846, line 2 (Dr. Meitzen).

162 Examples include firms that experience very large customer count percentage increases in one year that are followed by almost equivalent large customer count percentage decreases in the following year(s). These are evident in Exhibit 20414-0417, the spreadsheet replication of the Lowry study by Dr. Meitzen. Specific examples include, but are not limited to, Niagara Mohawk Power Corporation, +32.2 per cent in 2001 and -35.7 per cent in 2003; and Green Mountain Power Corporation, +14.4 per cent in 2012, and -13.14 per cent in 2013.

that would apply to evaluating analysis that utilizes raw (unpatched) data which has not been examined and, if necessary, adjusted, with reasoning and documentation provided, for the presence of anomalies. None of the studies are perfect in this regard, but there are no clear general guidelines on when data are unsuitable for analysis, and all the studies appear to have attempted to ensure that the data were satisfactory for use in their analysis.

134. In terms of the likely magnitudes of the effects on output growth due to this patching, for the 53 firms in common to the Lowry and Brattle study data sets, for the period 2000 to 2014, average annual growth using the patched customer count data (Lowry study) is 0.88 per cent, while the unedited Form 1 customer count data (as used by Dr. Meitzen) yields average annual growth of 0.99 per cent.[163] So for these firms and this period, the difference in output growth measures, arising just from the particular data set used for the number of customers, which translates directly into TFP growth differences, is of the order of 0.10 percentage points.

135. In addition to these differences pertaining to data on number of customers, the two forms (FERC Form 1 and EIA Form 861) also have different volume data for some utilities and years. The Lowry study highlights this issue in reply evidence, pointing out differences between sales volumes and delivery volumes, arguing that the latter, provided in Form 861, are a better measure due to the restructuring that occurred with investor-owned electric utilities in the U.S.[164]

136. Both the Brattle and Meitzen studies limit their volume data to those provided on FERC Form 1, thus precluding an examination of the effects of these data differences. In an IR response to the Commission, Dr. Lowry provides TFP calculations, using his methodology and assumptions, but using volume rather than the number of customers as the output measure and, alternately, using the different output data sources.[165] For his full sample of 88 utilities, for the period 1997-2014, output growth is 0.28 per cent using Form 1 data only, but 0.91 per cent using data combined from Form 1 and Form 861. With input growth for this period of 0.42 per cent, the corresponding average TFP growth measures are -0.14 per cent and +0.49 per cent, respectively, a difference of 0.63 percentage points that also changes the sign of average TFP growth from negative to positive.

137. Based on the evidence provided, the Commission observes that different choices for the output variable result in different output, and hence TFP, growth values. These growth values are consistently higher using number of customers as the output variable, and this relative ranking appears to be maintained even if different data sources are used. The Commission's findings in respect of the variability in TFP growth rates, resulting from differences in the output measure, follows the discussion of the various other factors such as time periods used in the TFP growth studies, and can be found in Section 5.4 below.

5.2.5 Time period

138. The final component of the TFP growth studies in which there was some disagreement among parties concerned the time period to be used for calculating TFP growth. This section

[163] The three sets of customer count data are in Exhibit 20414-X0417, as described in footnote 160. Firms that are not common to the two studies are deleted, as described in footnote 140. For the reported comparisons, in both cases annual growth is calculated separately for each firm and then averaged across firms for each year. See footnote 155.

[164] Exhibit 20414-X0468, CCA reply evidence of PEG, pages 6-10.

[165] Exhibit 20414-X0321, CCA-AUC-2016APR15-009(f), with spreadsheet attachments in Exhibit 20414-X0266. Analysis is performed using code rather than spreadsheets.

considers different choices for the time period, and the effect of such choices on the resulting TFP growth values. As with the input assumptions and output choices, consideration of this issue helps to inform the Commission about the range of values that the TFP growth component of the X factor can take, and how sensitive this range is to different sets of assumptions.

139. Although the Brattle and Meitzen studies both calculate TFP growth for each year from 1972 to 2014, as described in Table 1, they recommend basing the TFP growth component of X on some type of average using just the most recent 15 years of data. For comparison purposes, these studies calculated the average TFP growth based on the full 1972-2014 period to be approximately +0.75 per cent.[166] The Lowry study only has data from 1997 to 2014, and as shown in Table 1, bases its recommendation for the TFP growth component of the X factor on that full period.

140. In argument, the CCA, sponsor of the Lowry study, recommends that if a TFP growth factor is to be based on the NERA data set, it should use the full sample period.[167] One reason for this recommendation is based on the suggestion that the TFP trend calculated using number of customers as the output measure, as in the Lowry study, is more stable and, therefore, a long-term trend can be identified with a shorter sample period,[168] with the apparent corollary being that without this stability of data, a longer sample period would be required to identify the long-term trend. However, although it would appear to be correct that the number of customers as an output measure is more stable than a volumetric measure over a shorter sample period, it does not necessary follow that stability for a volumetric measure is any different over the long term when compared to a customer measure since number of customers data for years prior to 1997 were not provided in evidence. Accordingly, the Commission regards this stability conclusion as being speculative.

141. A second reason for the CCA's recommendation to use the full sample period if the NERA data set is used is that "The most principled basis for choosing a sample period in this proceeding is to capture a period in which productivity growth drivers are most similar to those facing Alberta utilities in the long run,"[169] and recent years, as recommended by the Brattle and Meitzen studies, do not reflect this. The Brattle and Meitzen studies do not support this view because their analyses are not based on utilities selected for characteristics similar to those of the Alberta distribution utilities. Therefore, based on the evidence provided, the Commission considers that the time period that should be used to determine TFP growth based on the NERA approach, as in the Brattle and Meitzen studies, is an open question for determining the TFP growth value to be used in the next generation PBR plans.

142. Both the Brattle and the Meitzen studies argue that the annual TFP growth series has changed over time in a way that causes TFP growth data from recent years to be a better determinant or predictor of TFP growth that can be expected during the next generation PBR term. The Brattle study does this through a series of statistical tests designed to show that

166 Exhibit 20414-X0396, Brattle TFP calculation update spreadsheet, reflective of Dr. Meitzen's correction and balanced panel. From data in Exhibit 20414-X0074, Table B.1 on PDF page 238, the Meitzen study calculated average 1972-2014 TFP growth to be 0.71 per cent. In response to Commission IRs, Exhibit 20414-X0256, PDF page 41, the 0.75 per cent TFP growth number was calculated based on Brattle's sample and balanced panel.
167 Exhibit 20414-X0630, CCA revised argument, paragraph 139.
168 Exhibit 20414-X0630, CCA revised argument, paragraphs 172-173.
169 Exhibit 20414-X0630, CCA revised argument, paragraph 165.

average TFP growth in recent years is significantly different to average TFP growth from 1972 to 1999.[170] In addition to their own tests, which the Commission finds to have limited usefulness due to their tendency to test differences of means between periods that overlap without sufficient statistical support for such a testing strategy, Brattle also undertook additional testing in response to IRs from the Commission. These test results indicate significant differences between means (of annual TFP growth rates) in the period 1972-1999 versus the ensuing 15 years, and in the period 1972-2004 versus the ensuing 10 years.[171] Structural change (Chow) tests conducted by Brattle, testing whether the parameters underlying TFP growth in one period are significantly different from those in the subsequent period, although subject to the caveats they describe, at the very least point to evidence of instability in the TFP growth rates beginning somewhere in the mid to late 1990s. These tests, however, do not formally identify any one particular year or combination of years where a structural break may have occurred.[172] Dr. Meitzen's test results, pertaining to non-stationarity tests with possible structural breaks, provided in an undertaking, also support this instability conclusion. For example, in the 1972-2014 sample, depending on the test chosen and how it is implemented, he found significant breakpoints in TFP growth at 1985, 1986, 1989, 1990, 1996, 2004, 2008 and 2010.[173] Dr. Meitzen concludes that "many of the breakpoints are at least 15 years from the end of the series, providing support that a 10- to 15-year time period appropriately captures the behavior of this series in the latter time period."[174]

143. Although not utilizing a formal testing strategy for structural breaks, the Meitzen study recommends a time period involving the last 15 years based on its focus on the Commission's interpretation, noted previously, that the X factor, in general terms, can be viewed as the expected annual TFP growth during the PBR term. The Meitzen study interprets this to mean that "the role of a TFP study in determining the X factor is <u>as a predictor of</u> expected annual productivity growth over the course of the subsequent price cap term"[175] (emphasis added). Subsequently, the Meitzen study calculates an average of (i) the average of annual TFP growth over the previous 10 years, and (ii) the average of annual TFP growth over the previous 15 years (the 10/15 moving average) and shows that between 1987 and 2009, generally (since 1998) this has been a better predictor of TFP growth for the next five years (a "forward-looking five-year average") than the NERA approach of using the average of all previous years.[176] Although the Meitzen study shows that since 1998 the 10/15 moving average is "closer" to the forward-looking five-year average than is the average of all previous annual TFP growth values,[177] "closeness" is a relative term, and no level of statistical significance is attached to the improvement for the 10/15 method that this figure demonstrates. Alternative methods (10/12, 8/15, etc.) could yield predictors that are even closer.

144. The Meitzen study recognizes that the 10/15 method is not necessarily the best predictor, but argues that it avoids cherry-picking dates or time periods, and that qualitatively similar results are obtained using a simple 10-year or 15-year moving average.[178] The choice of 10 to 15 years is based on the general span of recommendations made by parties in Proceeding 566,

170 Exhibit 20414-X0387, Brattle reply evidence, page 20, Q/A 41.
171 Exhibit 20414-X0173, PDF pages 22-26; Exhibit 20414-X0175.
172 Exhibit 20414-X0173, PDF pages 27-31; Exhibit 20414-X0175, tabs "Request (e)(ii)," "Request (e)(iii)."
173 Exhibits 20414-X0599 and 20414-X0601.
174 Exhibit 20414-X0599, page 2.
175 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, PDF page 214.
176 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, pages 34-37, PDF pages 220-224.
177 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, Figure 4a on PDF page 223.
178 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, PDF pages 218 and 221.

with Dr. Meitzen arguing that "this span of years provides a sufficiently long period that overcomes transient, short-run shocks that could influence TFP growth (such as with a 5-year average) and also avoids anchoring the forward-looking estimate with values from the distant past that no longer provide a reasonable basis for establishing a forward-looking X factor."[179] A drawback of the 10/15 method compared to simple averages of either the last 10 or last 15 years is that the last 10 years appear in both components that are averaged in the 10/15 method and, therefore, have higher weights than do the five years that precede them. A different choice of years (such as 8/13) would necessarily result in a different weighting scheme. This unequal weighting can only be avoided with a simple average and for this reason, the Commission prefers this latter approach.

145. The effect of the Commission's determination to dismiss the Meitzen study recommendation of the 10/15 method in favour of a simple average is to increase the lower bound of recommended TFP growth values in Table 1, which was previously associated with the 10/15 method. Again, however, due to the variability that results from the use of different assumptions underlying input growth, and the choice of the output measure, as described in the previous sections, and accounting for this variability means that this TFP growth component is not necessarily prevented from lying below the lowest remaining final recommendation (as shown in Table 1) of -0.79.

5.3 Stretch factor

146. Generally speaking, a stretch factor is an additional percentage incorporated in the X factor, thereby increasing the overall value for X and thus slowing the price or revenue cap growth determined by the I-X indexing mechanism. On this basis, the stretch factor can be viewed as sharing with customers the expected additional cost reductions that result from the move from a low-incentive regime such as COS regulation to a higher-incentive regime such as PBR. For this reason, stretch factors are common in first-generation PBR plans.

147. In this proceeding, parties disagreed on whether a stretch factor should be applied in the next generation PBR plans. The distribution utilities and their experts contended that readily available efficiency gains (the "low hanging fruit") have already been captured in the current generation PBR term.[180] In contrast, all interveners argued for a continuation of a stretch factor in the next generation PBR term in an amount not lower than the 0.2 per cent approved in Decision 2012-237.[181]

148. Among other arguments, the interveners submitted that a stretch factor is necessary as it strengthens the incentives under PBR.[182] On this point, the Commission disagrees. As indicated in Decision 2012-237, while the size of a stretch factor affects a utility's earnings, it has no

179 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, PDF page 219.
180 Exhibit 20414-X0056, Brattle evidence, page 36, Q/A 70; Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 43; Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 44; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 79; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraph 60; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 92-94.
181 Exhibit 20414-X0630, CCA revised argument, paragraph 204; Exhibit 20414-X0618, UCA argument, paragraph 86; Exhibit 20414-X0625, Calgary argument, paragraph 77.
182 Exhibit 20414-X0625, Calgary argument, paragraph 75. Exhibit 20414-X0618, UCA argument, paragraphs 74 and 88. Exhibit 20414-X0630, CCA revised argument, Section 12 was titled "Including a Stretch Factor Will Increase Efficiencies Not Yet Realized."

influence on the incentives for the utility to reduce costs. PBR plans derive their incentives from the decoupling of a utility'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).[183]

149. Brattle confirmed this observation stating that the existence of a stretch factor does not increase the benefits seen by customers. Rather, a stretch factor benefits customers because it provides the expected gains of PBR to them more quickly than the alternative of waiting until rebasing.[184] Brattle explained:

> … 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).[185]

150. Dr. Weisman expressed a similar view and indicated that "the question is whether those efficiency gains, to the extent they exist, the additional efficiency gains, should be guaranteed to consumers through the stretch factor rather than be passed along to consumers at the time of rebasing."[186] From this perspective, Dr. Weisman noted that the relevant factor for a regulator to consider when determining the need for the stretch factor is the certainty of additional efficiency gains, so as to make a decision on whether such gains should be passed along in the form of rebasing rather than guaranteed to consumers *a priori* through the stretch factor in the PBR formula.[187]

151. The distribution utilities and their experts have interpreted the Commission statement in paragraph 479 of Decision 2012-237 to mean that the inclusion of a stretch factor is warranted only during a transition from COS regulation to PBR.[188] Although the context for paragraph 479 concerned a transition from COS to first-generation PBR, the UCA's more general interpretation is that a stretch factor was approved in Decision 2012-237 because increased efficiencies were expected to be realized from the transition from a low incentive regulatory regime (in that case, COS) to a higher incentive regulatory regime (in that case, first-generation PBR). In the UCA's view, a better general definition of the purpose for a stretch factor is to share the efficiency gains that are expected to result when the subsequent generation of regulatory framework provides enhanced incentives relative to the previous generation (i.e., when there is a transition from a less-incentivized form of regulation to regulation that embodies greater incentives).[189]

152. Parties in this proceeding pointed out that because expenditures under the capital tracker mechanism in the 2013-2017 PBR plans were largely treated on a COS basis, they were not

183 Decision 2012-237, paragraph 500.
184 Exhibit 20414-X0387, Brattle reply evidence, page 47, Q/A 97.
185 Exhibit 20414-X0056, Brattle evidence, pages 35-36, Q/A 68.
186 Transcript, Volume 14, page 2915, lines 11-17 (Dr. Weisman).
187 Transcript, Volume 14, page 2915, lines 18-23 (Dr. Weisman).
188 Exhibit 20414-X0623, EPCOR argument, paragraph 79; Transcript, Volume 14, page 2917, lines 4-10 (Dr. Weisman); Exhibit 20414-X0446, Brattle supplemental reply evidence, page 9, Q/A 24; Exhibit 20414-X0624, Fortis argument, paragraph 70.
189 Exhibit 20414-X0618, UCA argument, paragraphs 73 and 77.

subject to the same high-powered incentives to control costs as the expenditures under I-X.[190] The Commission agrees. In Section 6 of this decision, the Commission approves the K-bar mechanism, which, as Dr. Weisman put it, is "a lot more high powered in terms of incentives,"[191] compared to capital trackers. Mr. Baraniecki for EPCOR agreed with the logic that if capital is moved from a low-powered incentive regime, such as capital trackers, to a higher-powered incentive regime, such as K-bar, there may be a need for a stretch factor.[192]

153. Given that current generation PBR plans include a COS-based capital trackers mechanism, which will be mostly replaced in the next generation PBR plans by the K-bar mechanism, the Commission expects that next generation PBR plans will be largely devoid of any significant COS elements. Therefore, the Commission finds merit in including a stretch factor component in the X factor for the next generation PBR plans for all distribution utilities. In a similar vein, because ENMAX was regulated under COS in 2014, the commencement of the 2015-2017 PBR plan warrants inclusion of a stretch factor in the X factor for the ENMAX 2015-2017 PBR plan as well.

5.4 Commission determination on the X factor for the 2018-2022 PBR plans

154. The TFP growth values that have been produced by the various studies in evidence are the result of an index-number type of calculation, rather than estimation, that can (but need not) be obtained using a spreadsheet. Despite this characteristic, even were the examination of the three TFP growth studies in this proceeding limited to a period comprising the last 15 years, a range included in all three studies, the range of TFP values that have been proposed for this period is strikingly large. Brattle expressed its view that "it is unusual for there to be more than one TFP study in evidence in a single proceeding,"[193] as in the case of the current proceeding where three TFP growth studies were filed, at least two of which involve some fundamental differences. Had only one objective and transparent study been filed in evidence, the variability inherent in the TFP growth value, which is a function of the assumptions and data used, and is evident from a comparison of the three studies, easily could have remained unknown. This could have led the Commission to conclude that there is a single TFP growth value that could be regarded as "correct." Rather, the Commission views the variety of results that have been provided as confirming that the TFP growth value is likely not a correct single number, but that a reasonable value likely falls within a range of values, demarcated by the breadth of assumptions and data sets that may be reasonably employed in producing the studies. This view was shared by some of the experts in this proceeding. For example, in its evidence, Brattle indicated that "Certainly estimating TFP trends is not an exact science."[194] This opinion was explained further in testimony by Dr. Carpenter when he stated the following:

> There's noise in the data, and there's noise in the results. So I think you have to take a practical view as to how much uncertainty there is in these numbers. I think at some point in our evidence we say there's probably about 150 basis points of potential just noise in

190 Transcript, Volume 1, page 63, lines 3-8 (Dr. Brown); Transcript, Volume 12, page 2443, line 12 to page 2444, line 8 (Dr. Lowry); Transcript, Volume 14, page 3021, lines 2-21 (Dr. Weisman); Exhibit 20414-X0618, UCA argument, paragraph 83.
191 Transcript, Volume 14, page 2918, lines 15-18 (Dr. Weisman)
192 Transcript, Volume 14, page 2932, line 15 to page 2933, line 12 (Mr. Baraniecki).
193 Exhibit 20414-X0387, Brattle reply evidence, page 43, Q/A 85.
194 Exhibit 20414-X0387, page 43 Q/A 85.

> the TFP results. The minus .79 figure that we've referred to is a midpoint in a wide range.[195]

155. It is this observation that allows the reconciliation of two quite disparate statements made by different experts at the hearing concerning TFP growth values, the authors of the Brattle study who "don't think that … there's a right answer necessarily"[196] while Dr. Lowry emphasized that his result "is computed to four decimal places."[197] Once a set of assumptions, concerning all aspects of the calculation have been determined, such as input and output growth measures, source for output and input data, and all the many other considerations, some of which were discussed in Section 5.2, then what is left is a calculation, and it can be computed to as many decimal places as the data will support. However, should a change be made to one aspect of any one of a number of assumptions, then a different numerical value will result.

156. As shown in Table 1, all final recommendations concerning the TFP growth component of the X factor are lower than, and in some cases much lower than, the TFP growth number of +0.96 per cent adopted by the Commission in Decision 2012-237. Consequently, as noted previously, based on the expert evidence received in this proceeding, the issue before the Commission is not whether the TFP growth component of the current X factor needs to be lowered for the next generation PBR, but rather the extent to which it needs to be lowered. To address this issue, the Commission has evaluated the applicability of the various TFP growth values provided by the expert evidence presented in this proceeding.

157. Based on the criteria of objectivity, consistency and transparency, the Commission finds, in Section 5.2.1, that equal weights should be applied to the Brattle and Meitzen studies, and to the Lowry study that was provided in direct evidence. Further, since the effect of input data modifications made in the studies is minimal, as discussed in Section 5.2.2, the Commission also will not weight the studies differently due to the use or non-use of such modifications.

158. The Commission found in Section 5.2.2 that the subsample analysis in the Lowry study can provide useful information, but analysis using the full sample, or possibly subsamples selected on multiple criteria, better informs the Commission's judgement as to the possible range of TFP growth values that are reflective of competitive markets. For this reason, the Commission limited further consideration of the Lowry study to TFP growth findings for the full sample of 88 firms. Since the highest recommended TFP growth values were obtained from the Lowry study subsample, focusing on the full sample in the Lowry study suggests a downward adjustment to the TFP growth component compared to its previous value. Of course, there is considerable variability due to the different assumptions that are made, and accounting for this variability means that this TFP growth component is not prevented from exceeding the highest remaining recommendation.

159. In Section 5.2.3, the Commission found that the input growth assumptions used by each expert to be reasonable. Based on this finding and the critiques provided by other parties, the Commission cannot rule out any of the corresponding TFP growth numbers. However, the Commission notes that the input growth assumptions are crucial, in that changing the assumptions leads to significant variability in the TFP growth value.

195 Transcript, Volume 3, page 430, line 19, to page 431 line 1.
196 Transcript, Volume 4, pages 663-664.
197 Transcript, Volume 12, page 2480, line 13.

160. The choice of output measures, and associated assumptions, discussed in Section 5.2.4, were all found to be valid by the Commission. Based on this finding and the validity of the various critiques that were provided, the Commission cannot rule out either of the volumetric or number of customers output measures, nor the TFP growth values that follow from different assumptions. As discussed in that section, in view of this finding, the Commission believes that a useful way to proceed in future TFP growth studies might be to use some combination of the output measures, and, as a starting point, to examine the sensitivity of the TFP growth results to different combinations of output measures. Based on analysis presented in this proceeding, however, changing the output measure leads to moderate variability in output growth, and hence, in TFP growth.

161. The time period used to determine the TFP growth value, considered in Section 5.2.5, is important. The starting point for the Commission's analysis in this proceeding is the Commission's finding in Decision 2012-237, which continued to be supported by some parties in this proceeding, that the longest available time period best reflects the long-term TFP growth that has the greatest relevance in determining the X factor. This is especially the case when the PBR plan includes a capital mechanism that can be used to account for the idiosyncratic nature of utilities. Specifically, it is the capital mechanism, in part, that can respond to shorter term shocks to TFP, including the health of the economy. Despite this desire for the longest available time period, several features of the analysis, in the TFP growth studies that were provided, support an argument for placing less weight on the longest available time period. These features include the possibility of structural breaks, and the practical problem of the length of the time series data associated with a particular choice of output measure (number of customers). Since numerical values of all the output measures are not available for the same length of time, the only consistent time periods for comparison of all the TFP numbers is 15-17 years. Nevertheless, given the evidentiary support demonstrating that the longest available time period best reflects the long-term TFP growth for using the longest available time period for determining TFP growth, the Commission places some weight on the longest-term TFP growth results presented in evidence, namely, the approximately +0.75 value determined for the 1972-2014 period.[198]

162. As a result of the above analysis, the Commission considers that the range of TFP growth values is defined by three remaining values: -0.79 for the Brattle study, and +0.43 for the Lowry study, both from Table 1, and approximately +0.75 for the full 1972-2014 time period. In addition, based on the analysis in sections 5.2.3 to 5.2.5, additional information about the variability of these TFP values to changes in assumptions and hence, the possible range of values that TFP growth might take, is available.

163. Dr. Meitzen indicated that he does not view a TFP growth study as open to any number of assumptions or data sets and that "there's a right way of doing them."[199] As set out earlier in Section 5.2, it was EPCOR's recommendation that the X factor for the next generation PBR plans be established at the time of rebasing, employing Dr. Meitzen's TFP growth calculation methodology and using the most recent available data.[200] In a similar vein, the UCA submitted that "the Commission should ultimately approve an X Factor for the second generation PBR plan calculated on the basis of a TFP study that is correctly prepared;" that is, "using appropriate input and output indices, as well as the appropriate time period and sample, as determined

198 In response to Commission IRs, Exhibit 20414-X0256, PDF page 41, the 0.75 per cent TFP growth number was calculated by Dr. Meitzen based on Brattle's sample and balanced panel.

199 Transcript, Volume 14, page 2885, lines 11-13 (Dr. Meitzen).

200 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 95.

through statistical testing."[201] In its argument, the CCA, sponsor of Dr. Lowry's study, recommended selecting one of the specific numerical values of TFP growth put on the record of this proceeding, to "discourage witnesses from filing extreme recommendations in the hopes that the Commission will choose a number in the middle."[202]

164. These statements appear to suggest that there is just one correct TFP growth number and any others that are provided are just distractions. The Commission does not subscribe to this view, and considers it has, in fact, benefitted from examining different TFP growth studies in this proceeding that rely on different assumptions and calculations pertaining to the input and output measures. However, studies must provide information describing <u>all</u> aspects of the study, with considerable detail – including easily reproducible supporting calculations – on the effects, both separately and jointly, of changing <u>each</u> of the assumptions used, where the set of assumptions is widely defined, and includes assumptions with respect to data source selection. In the absence of such complete information, the Commission must take the limited set of information that it does have, and apply its expertise and judgement to the available evidence provided in this proceeding to arrive at a TFP growth value to be used as a component of an X factor for the next generation PBR plans.

165. In promoting his approach to determining the TFP growth value to use as a component of the X factor, Dr. Meitzen focuses on determining how well TFP growth calculated using an average annual value over a long period, succeeds at forecasting annual average TFP growth over the ensuing five years compared to a calculation using a shorter data period; that is, the length of the next generation PBR term.[203] Using volumetric output data, the Meitzen study shows that using an average based on all previously available annual TFP growth performed poorly over the 2009-2014 period, and that an average based on a shorter period performed better.[204] While the Commission finds this evidence to be informative, it is not conclusive, since it only pertains to one particular TFP growth outcome, using one particular set of assumptions. In the Commission's view, the knowledge that one particular methodology, including all the assumptions it involves, is a poorer predictor if longer, rather than shorter, data series are used in its construction, does not generalize to all other methodologies. For example, a methodology that involves a customer count output measure, or combined volumetric and customer count output measures, with particular types of weighting, and involving certain other choices, may perform very well in this forecasting context even if its construction were to be based on a longer data period, should it be available.

166. As a further consideration, the Commission notes the concern that has been expressed by Calgary and the UCA with a negative value of the X factor.[205] Experts for the distribution utilities pointed out that incentives are not affected by the choice of a particular value of the X factor, whether it is negative, zero or positive, except to the extent that the value selected may affect availability of incremental capital funding through particular capital tracker mechanisms.[206] Rather, these incentives derive from the decoupling between revenues and costs that is explicit in

201 Exhibit 20414-X0618, UCA argument, paragraphs 56-57.
202 Exhibit 20414-X0630, CCA revised argument, paragraph 139.
203 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, PDF pages 214-219.
204 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, PDF pages 220-224.
205 Exhibit 20414-X0625, Calgary argument, paragraphs 69-73; Exhibit 20414-X0618, UCA argument, paragraphs 58-63.
206 See, for example, Exhibit 20414-X0619, PDF pages 13-14 (ENMAX, Brattle); Exhibit 20414-X0623, PDF pages 17-18 (EPCOR, Dr. Weisman).

a PBR plan. The Commission agrees. However, the Commission also is aware that indexing prices or revenues by I-X is based on the idea that part of the expected efficiency gains from PBR are passed on to consumers during the PBR plan term through the X factor, regardless of the actual performance of the distribution utilities.[207] The appeal of this approach to consumers is obviously decreased when there are efficiency losses, and the value of X is negative.

167. The Commission is aware that the value of the X factor can be negative, and there was considerable discussion of this issue in Decision 2012-237, as well as in this proceeding. However, given the manner in which TFP growth is calculated in the studies in evidence, negative values of TFP growth mean that more inputs are used to produce the same amount of output or that less output is produced using the same amounts of inputs. Any industry, including the electricity (and gas) distribution industry, may have periods when this phenomenon is observed, but it is not clear why such a phenomenon should persist over a long period. In the Brattle and Meitzen studies, TFP growth is negative in nine of the last 15 years, and more particularly, in seven of the last nine years.[208] Yet, many of the utilities in the current proceeding went to great lengths to explain some of the efficiency-improving procedures (productivity improvements) they have adopted, and there is no reason to expect that at least some of this type of behaviour would not be observed in many of the U.S. firms in the sample used in the TFP growth calculations being examined here.[209] These findings suggest that there may be some concerns with the calculation of TFP growth using only volume as the measure of output, whatever the time period used, especially when combined with the particular data and input growth assumptions utilized in the Brattle and Meitzen studies, with the sample of U.S. electric distribution utilities. The evidence is not conclusive, but it does cause the Commission to be mindful of the extent to which the results differ with different choices of assumptions, including output measures.

168. Finally, all parties in this proceeding indicated a common X factor, based on their preferred TFP growth number, could be applied to both gas and electric utilities.[210] Further, apart from Dr. Lowry's proposal to focus on subsamples of the U.S. electric distribution utilities that, in his view, were likely to be more representative of conditions faced in Alberta (which the Commission discounted in Section 5.2.2), no party recommended making any specific adjustments to account for the fact that the TFP growth component of the X factor for the Alberta distribution utilities is based on the average rate of TFP growth in the U.S. electric distribution industry.[211] In addition, as observed above, the inclusion of an incremental capital funding mechanism in the next generation PBR plans helps to address the unique requirements of

207 See Decision 2012-237, paragraph 17. Additional efficiency gains may be passed to consumers through the rebasing mechanism.

208 Exhibit 20414-X0396, updated Brattle study; Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, Table B.1, PDF page 238.

209 This may point to a need, in future TFP growth studies using these U.S. utilities, to focus on the type of regulation they face and, in particular, the period that they were regulated under a PBR-type of approach.

210 Exhibit 20414-X0619, ENMAX argument, paragraph 76. Transcript, Volume 1, page 413, lines 16-24 (Dr. Brown); Transcript, Volume 14, page 2881, lines 16-24 (Dr. Meitzen); Transcript, Volume 12, page 2410, lines 2-25 (Dr. Lowry); Exhibit 20414-X0625, Calgary argument, paragraph 74. The UCA, in its argument, Exhibit 20414-X0618, at paragraph 56, recommended that "the Commission should ultimately approve an X Factor for the second generation PBR plan calculated on the basis of a TFP study that is correctly prepared."

211 Although Brattle noted in their evidence, Exhibit 20414-X0056, page 34, Q/A 64 that the existence of a positive productivity gap between the U.S. and Canadian economies means that their X factor recommendation "is more likely to be too high than too low."

each of the distribution utilities in the Alberta context, consistent with the Commission's five PBR principles.

169. The Commission has determined an X factor, using its judgement and expertise in weighing the evidence and in taking into account the multitude of considerations set out above, in particular evidence demonstrating that the TFP growth value cannot with certainty be identified as a single number, but rather, in view of the variability resulting from the assumptions employed, must be considered as falling within a reasonable range of values, between -0.79 and +0.75. The Commission finds that a reasonable X factor for the next generation PBR plans for electric and gas distribution utilities in Alberta, inclusive of a stretch factor, will be 0.3 per cent.

5.5 X factor for ENMAX's 2015-2017 PBR plan

170. Decision 21149-D01-2016 approved an interim X factor for the ENMAX 2015-2017 PBR plan, with the direction that the final X factor will be determined in the present proceeding.[212] ENMAX submitted that the same X factor, based on Brattle's recommendation, should apply to both of its 2015-2017 and 2018-2022 PBR plans.[213]

171. The UCA recommended that the 0.96 per cent X factor, based on the TFP growth number approved in Decision 2012-237, be used for ENMAX's 2015-2017 PBR plan, given that this plan is, in most material respects consistent with the PBR plans approved in Decision 2012-237. In the alternative, the UCA recommended that the 0.80 per cent X factor, based on the TFP growth number approved for ENMAX's FBR plan in Decision 2009-035, and approved as an interim measure in Decision 21149-D01-2016, be approved.[214]

172. Given the updated TFP growth numbers put forward in this proceeding, including the extension of that data series from 2010 to 2014, the Commission considers that it would not be reasonable to base the X factor on the TFP growth numbers approved in prior decisions dating back to 2009 or 2012. Further, as ENMAX highlighted, in this proceeding, the Brattle and Meitzen studies specifically undertook to update NERA's TFP growth numbers on which the Commission relied in Decision 2012-237.[215] Therefore, based on its considerations of the TFP growth numbers and a stretch factor as set out earlier in this decision, the Commission finds that the same X factor of 0.3 per cent that has been determined for the next generation PBR plans for all gas and electric distribution utilities should also apply to the ENMAX 2015-2017 PBR plan.

5.6 Proposals for a non-negative I-X provision

173. The five distribution utilities sponsoring Brattle's evidence proposed that the value of the I-X index should be restricted to be non-negative with zero as a lower bound (i.e., in years when the I-X index value is negative, the index would be held at a floor of zero per cent). ENMAX asked for the same provision to apply to its 2015-2017 PBR plan.[216]

174. These distribution utilities submitted that the value of the input price inflation measure in PBR plans, the I factor, has recently entered the negative range, and that a positive value of the X factor would tend to enhance this (i.e., cause I-X to be even more negative), at a time when

212 Decision 21149-D01-2016 (Errata), paragraph 53.
213 Transcript, Volume 8, page 1467, lines 10-12 (Mr. Hildebrandt).
214 Exhibit 20414-X0618, UCA argument, paragraphs 70-71.
215 Exhibit 20414-X0634, ENMAX reply argument, paragraph 71.
216 Exhibit 20414-X0619, ENMAX argument, paragraph 94.

utilities are finding that many of their costs, such as those flowing from union agreements, are escalating at a positive rate.[217] Brattle experts expressed their view that if the I factor in the PBR formula were to be negative, that could signal that the approved inflation measure is not representative of the price changes facing the utilities.[218] The five distribution utilities agreed with this observation and submitted that a non-negative I-X provision would allow them to mitigate the issues with the approved inflation measure. AltaGas and ENMAX called for a revision of the I factor in some future proceeding.[219]

175. EPCOR confirmed it did not make a request for a non-negative I-X provision in its next generation PBR plans. At the hearing, Mr. Baraniecki indicated that even though EPCOR is facing the same conditions as other distribution utilities, it did not apply for such a provision because it was inconsistent with the principles of PBR.[220] The UCA agreed with EPCOR's view that there is no principled basis on which to impose a floor of zero on the I-X value.[221]

176. The I factor value is not within the scope of this proceeding; however, the proposal to restrict I-X to be non-negative can also be framed as a recommendation involving the X factor value.[222] As such, the Commission has considered this request.

177. Dr. Brown and Dr. Carpenter for Brattle, Dr. Meitzen and Dr. Weisman for EPCOR and Dr. Lowry for the CCA, indicated that there is no apparent theoretical basis for restricting I-X to be non-negative.[223] The Commission agrees and accordingly, will not impose such a provision at this time. Specifically, restricting I-X to be non-negative may result in blunting of incentives to control costs for certain categories of expenditures. As well, the I-X index value is just one component of a number of interacting components of the next generation PBR plans. As set out in Section 9, in designing next generation PBR plans, the Commission has considered all relevant factors, including those that may affect the distribution utilities during the next generation PBR term – such as the current economic climate in Alberta – that the non-negative I-X proposal was aiming to address.

6 Treatment of capital additions

178. In Decision 2012-237, the Commission recognized that while the TFP study used in determining the X factor for the Alberta distribution utilities reflected a rate of long run productivity growth for a set of distribution utilities over time and, therefore, necessarily included capital input costs, there are nevertheless circumstances where an Alberta distribution utility may require capital funding in addition to the funding generated under the I-X mechanism

217 Exhibit 20414-X0619, PDF pages 29-31; Appendix A, PDF pages 47-48 (ENMAX); Exhibit 20414-X0622, PDF pages 25-26 (ATCO); Exhibit 20414-X0624, PDF pages 21-22 (Fortis); Exhibit 20414-X0639, PDF pages 10-11 (AltaGas).

218 Exhibit 20414-X0173, BRATTLE-AUC-2016APR15-011(b).

219 Exhibit 20414-X0639, AltaGas reply argument, paragraph 31; Exhibit 20414-X0619, ENMAX argument, paragraph 94.

220 Exhibit 20414-X0256, EDTI-AUC-2016APR15-015(a) and Transcript, Volume 14, page 2939 lines 15-22 (Mr. Baraniecki).

221 Exhibit 20414-X0618, UCA argument, paragraph 67.

222 Specifically, if the Commission were to set some value of X, say X_0, the recommendation from the utilities could be expressed as: $X = \begin{cases} X_0, & if\ I > X_0 \\ I, & if\ I < X_0 \end{cases}$

223 Exhibit 20414-X0173, BRATTLE-AUC-2016APR15-011(b); Exhibit 20414-X0256, EDTI-AUC-2016APR15-015(c); Exhibit 20414-0321, CCA-AUC-2016APR15-012(b).

in order to provide for necessary capital additions.[224] To address this need, a capital funding mechanism referred to as a "capital tracker" was established. The capital tracker mechanism provided for a COS application process, whereby the revenue requirement associated with approved capital projects or programs could be reviewed, approved and collected from ratepayers by way of a K factor adjustment to the annual PBR rate-setting formula.

179. The capital tracker mechanism was intended to provide distribution utilities with a reasonable opportunity to recover their prudently incurred capital costs, including a fair return, and to recognize the unique circumstances of each regulated distribution utility, consistent with PBR principles 2 and 4. The criteria and processes established for capital tracker approvals were designed to ensure only necessary, incremental capital funding was awarded, while providing incentives for a distribution utility to fulfill its capital infrastructure requirements in an efficient manner, consistent with PBR principles 1 and 5. The implementation and application of the capital tracker criteria were considered in the 2013 capital tracker proceeding, leading to Decision 2013-435. Section 11 of Decision 2013-435 outlines the structure of capital trackers for the 2013-2017 PBR plans.[225] In Decision 21149-D01-2016, the use of capital trackers was approved for ENMAX for its 2015-2017 PBR plan, following the guidelines set out in Decision 2012-237 and Decision 2013-435.

180. In scoping the issues for the present proceeding, the need for and form of incremental capital funding in the next generation PBR plans was the third item on the final issues list established by the Commission in its letter dated August 21, 2015.[226] The Commission heard evidence on various matters relating to capital, as discussed in the sections of this decision that follow. Section 6.1 discusses the requirement of an incremental capital funding mechanism in the next generation PBR plans and Section 6.2 discusses the continuation of PBR as opposed to a return to a COS regulatory regime. Some parties to this proceeding proposed to split capital into two types that would be governed by separate capital mechanisms; this is discussed in Section 6.3. Section 6.4 addresses the various proposals for incremental capital funding mechanisms. Finally, Section 6.5 discusses the issues of service quality and asset monitoring.

6.1 Requirement of an incremental funding mechanism

181. Each of Brattle, the ATCO utilities, Fortis, ENMAX, AltaGas, EPCOR, Dr. Lowry, on behalf of the CCA, and the CCA, in argument, were of the view that an incremental capital funding mechanism is still required to provide adequate funding for capital additions in the next generation PBR plans.[227] Mr. Bell, on behalf of the UCA, and the UCA in its argument, recognized that there may be some circumstances where a distribution utility requires additional funding and Mr. Bell clarified that his proposal would include capital trackers, but on an exception basis.[228] Devon Energy Corporation Canada expressed its concern that without an

224 Decision 2012-237, paragraph 549.
225 Decision 2013-435, paragraphs 1093-1103.
226 Exhibit 20414-X0026, AUC letter - Final issues list, August 21, 2015, attachment, PDF pages 11-12.
227 Exhibit 20414-X0056, Brattle written evidence, PDF page 42, Q/A 79 and PDF page 46, Q/A 85; Exhibit 20414-X0070, ATCO utilities PBR plan proposal, paragraph 72; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraph 70; Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 46; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 80; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 99; Exhibit 20414-X0460, CCA-THYGESEN-LOWRY-AUC-2016JUN03-012; Exhibit 20414-X0630, CCA argument, paragraph 9.
228 Transcript, Volume 16, page 3402, lines 1-3 (Mr. Bell); Transcript, Volume 16, page 3405, line 5 to page 3406, line 9 (Mr. Bell); Exhibit 20414-X0618, UCA argument, paragraphs 95-96.

incremental capital funding mechanism, the capacity of distribution utilities to respond to emergent customer requirements would be impeded.[229]

182. In its PBR plan proposal, Calgary noted that its proposals apply only to ATCO Gas and stated that it "anticipates that there is potential for capital additions that cannot be financed under the (I–X) mechanism."[230] However, in its argument, Calgary stated that ATCO Gas has not demonstrated its need for incremental capital funding in its evidence and, as such, awarding a capital mechanism to ATCO Gas would award extra revenue where it is not needed.[231] In support of this position, Calgary noted that, all else equal, ATCO Gas would have been able to earn at least the approved ROE in 2013-2015 without any incremental capital funding. However, Calgary also noted that basing the going-in rates on the approved forecast for O&M-related revenue requirement in 2012 that was higher than actual O&M expenses in 2012 resulted in approximately $20 million of excess annual revenue, which remained with ATCO Gas for six years.[232] As noted previously, Mr. Johnson stated in testimony that had the going-in rates in 2012 been sufficient to just meet the allowed ROE in 2012, ATCO Gas would not have been able to earn its allowed rate of return because the I-X alone would not have provided sufficient funding.[233]

183. The Commission agrees with those parties that supported a continuing need for a form of incremental capital funding. Consistent with the findings in Decision 2012-237, the Commission continues to find that there is sufficient evidence that a capital mechanism in addition to I-X is required to deal with the unique circumstances of individual distribution utilities that may be in different places in their capital programs and business cycles. With respect to Calgary's position that ATCO Gas should not be permitted a mechanism to obtain incremental capital funding, the Commission finds no basis upon which to treat ATCO Gas differently than other distribution utilities with respect to the ability to access an incremental capital funding mechanism under the next generation PBR plans once going-in rates are set in the manner the Commission has determined.

184. The approved incremental capital funding mechanism for the next generation PBR plans is outlined in the following subsections.

6.2 Returning to cost of service

185. Prior to the implementation of PBR, electric and gas distribution utilities in Alberta were subject to a COS regulatory regime. Under this system, rates were set by testing an application from the distribution utility based on forecast costs generally for a one or two year test period. Although no party proposed a return to full COS regulatory regime and the abandonment of PBR as their preference for dealing with incremental capital funding issues, some parties noted the difficulties in selecting a method of funding incremental capital in a PBR environment and offered modifications to the traditional form of COS as an alternative regulatory regime which might enhance the efficiency of the process. These suggestions included returning to COS for

229 Exhibit 20414-X0615, Devon Canada argument, PDF page 1.
230 Exhibit 20414-X0071, Calgary PBR plan proposal, page 61, lines 11-12.
231 Exhibit 20414-X0625, Calgary argument, paragraphs 189-190.
232 Transcript, Volume 16, page 3323, lines 3-13; (Mr. Matwichuk); Exhibit 20414-X0071, Calgary PBR plan proposal, PDF pages 40-41.
233 Transcript, Volume 16, page 3364, lines 6-7 (Mr. Johnson).

capital only, a mandatory three-year test period, or a test period determined on a case-by-case basis in recognition of the unique circumstances of each distribution utility.[234]

186. The Commission does not consider that a return to a COS regulatory environment in full or in respect of capital only, in order to deal with incremental capital funding issues discussed in this proceeding, to be in the public interest. As noted in Bulletin 2015-10, the Commission indicated in commencing this generic proceeding its intention to continue with PBR regulation of electric and gas distribution utilities in accordance with the five PBR principles that the Commission adopted in the 2013-2017 PBR plans. Further, the Commission continues to consider PBR to provide superior incentives that will lead to greater efficiency in providing utility service and lower rates for customers than would be the case in a COS regulatory environment.

6.3 Type 1 and Type 2 capital

187. The 2013-2017 PBR plans distinguish between capital that is solely funded under the I-X mechanism and capital that is partially funded under the I-X mechanism and partially funded through a capital tracker. Several parties in the proceeding suggested dealing with incremental capital funding requirements by dividing capital additions on the basis of characteristics; for example, the ability of the distribution utility to forecast and control the capital additions.

188. Recognizing that various capital projects or programs within a distribution utility may be subject to different levels of management control and may have high levels of year-over-year volatility, the distribution utilities and Dr. Lowry, on behalf of the CCA, proposed to split all capital into two types to be managed under two separate incremental capital funding mechanisms.[235] The first type of capital was proposed to include projects and programs that cannot be fully funded under the I-X mechanism and do not qualify for Y factor or Z factor treatment, that meet the current capital tracker criteria but are generally outside of management's control, are otherwise unforecastable, or have a high degree of variability in costs from year to year. The distribution utilities and the CCA generally proposed that approval and subsequent review and true-up to actual costs of Type 1 capital tracker projects and programs would be done on a basis similar to how capital trackers are treated under the current generation PBR plans.

189. The second type of capital, would include all or most other capital that does not qualify for either Y factor or Z factor treatment, whether fully funded under the I-X mechanism or not. Type 2 capital would attract a different regulatory approach to incremental capital funding with the distribution utilities being given a predetermined amount of incremental capital funding for all or a portion of the PBR term. The distribution utilities would be expected to manage their capital programs within the capital funding constraints of the Type 2 amounts provided. Both the K-bar approach, as proposed by EPCOR and Fortis, and Brattle's F factor, as defined in

[234] Exhibit 20414-X0066, UCA evidence of Mr. Bell, page 32; Exhibit 20414-X0625, Calgary argument, paragraph 177; Exhibit 20414-X0616, AltaGas argument, PDF page 23; Exhibit 20414-X0619, ENMAX argument, paragraph 115; Exhibit 20414-X0453, PARTIES(FAI)-AUC-2016JUN03-013; Exhibit 20414-X0622, ATCO argument, paragraph 77; Exhibit 20414-X0638, CCA argument, paragraph 19; Transcript, Volume 11, page 2184, lines 6-9 (Dr. Lowry); Exhibit 20414-X0084, CCA evidence of Mr. Thygesen, paragraph 201.

[235] Exhibit 20414-X0056, Brattle written evidence, PDF pages 50-51, Q/A91; Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 52; Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 58; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 74-91; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 125-126; Exhibit 20414-X0460, CCA-LOWRY-AUC-2016JUN03-006.

Section 6.4, are examples of a Type 2 approach to capital funding. They each involve establishing a capital funding shortfall amount at the outset of the next generation PBR plan.

190. Dr. Weisman, on behalf of EPCOR, and Dr. Brown, of Brattle, noted that in designing an incremental capital funding mechanism, there is a trade-off between efficiency incentives and risk sharing that needs to be considered, and that the Type 1 and Type 2 categorization attempts to strike a balance between these two important concepts. Dr. Weisman noted that while it would be ideal to place as much capital under Type 2 as possible, it is also possible to go too far by pushing projects and programs into Type 2 for which the firm should not bear the risk. Ms. Sullivan, on behalf of Fortis, explained that there is a distinction between a competitive organization and a regulated distribution utility, which is that the costs associated with the obligation to serve really cannot be avoided by a distribution utility.[236]

191. Other parties noted that the process associated with splitting capital into two categories would increase regulatory burden.[237] The CCA expressed a concern with the amount of capital that could receive Type 1 treatment and noted that with a broad definition for the Type 1 criteria, capital trackers will expand to dominate the capital treatment as they have done under the 2013-2017 PBR plan.[238] Mr. Bell, on behalf of the UCA, expressed his concern that splitting capital into two categories "seems to be pushing risk on customers and away from the utility."[239]

192. In an attempt to define projects or programs that would qualify for Type 1 treatment, parties proposed a number of criteria, including unpredictable, not forecastable, unstable with large variances year over year, highly volatile, idiosyncratic, outside of management control, third-party driven, non-discretionary, triggered by exogenous events, contains risk the distribution utility should not have to assume, and the type of project that would have qualified for a deferral account under COS.[240] Dr. Brown, of Brattle, explained that the goal should be to identify only those costs or only those distribution utility operations which are entirely within the control of the distribution utility and are not subject to any outside drivers or influences, then apply PBR-type incentives to those projects or programs and treat the other costs, which are outside the distribution utility's control, on a pass-through or true-up basis. Dr. Weisman, on behalf of EPCOR, noted his view that whatever criterion is chosen, it needs to be exogenous to

236 Transcript, Volume 15, page 3089, line 25 to page 3090, line 7 (Dr. Weisman); Transcript, Volume 4, page 588, lines 8-14 (Dr. Brown); Exhibit 20414-X0056, Brattle written evidence, page 51, Q/A95; Transcript, Volume 15, page 3093, lines 1-7 (Dr. Weisman); Transcript, Volume 9, page 1828, lines 16-23 (Ms. Sullivan).

237 Exhibit 20414-X0451, PARTIES(UCA)-AUC-2016JUNE03-006; Exhibit 20414-X0460, CCA-THYGESEN-AUC-2016JUN03-006; Exhibit 20414-X0625, Calgary argument, paragraphs 152-153; Exhibit 20414-X0636, Calgary reply argument, paragraphs 40-41.

238 Exhibit 20414-X0638, CCA reply argument, paragraphs 44-46.

239 Transcript, Volume 17, page 3605, line 13 to page 3606, line 1 (Mr. Bell).

240 Exhibit 20414-X0056, Brattle written evidence, PDF pages 50-51, Q/A91; Transcript, Volume 4, page 549, lines 18-25 and page 558, line 14-24 (Dr. Carpenter); Transcript, Volume 5, page 926, line 17-25 and page 957, lines 8-17 (Mr. Stock); Exhibit 20414-X0255, ATCO-AUC-2016APR15-010; Transcript, Volume 7, page 1400, line 25 to page 1402, line 5 (Mr. Howell); Exhibit 20414-X0183, FAI-AUC-2016APR15-014; Transcript, Volume 9, page 1780, line 25 to page 1781, line 13 (Mr. Eck); Exhibit 20414-X0460, CCA-THYGESEN-LOWRY-AUC-2016JUN03-006; Transcript, Volume 11, page 2148, lines 16-21 and page 2154, lines 7-15 (Dr. Lowry); Exhibit 20414-X0456, PARTIES(EDTI)-AUC-2016JUN03-006; Transcript, Volume 14, page 3022, lines 9-15 (Dr. Weisman); Transcript, Volume 15, page 3070, lines 4-10 and page 3085, line 20 to page 3086, line 12 (Dr. Weisman); Transcript, Volume 15, page 3083, line 24 to page 3084, line 10 (Mr. Baraniecki); Exhibit 20414-X0638, CCA reply argument, paragraphs 44-46.

the distribution utilities.[241] Further to the attempts to define the criterion, parties identified some specific types of programs that should be included or excluded from the Type 1 capital mechanism.

193. Regarding growth programs, Dr. Lowry, on behalf of the CCA, noted that there are various arguments why growth-related capital additions should not be given incremental capital funding that the Commission explored and recognized in prior proceedings and submitted that growth-related capital additions should be excluded from any incremental capital funding mechanism. Mr. Baraniecki, on behalf of EPCOR, noted that while growth programs are not necessarily within their control, EPCOR is willing to take the risk on these programs at this time and has proposed growth to be included in K-bar. Dr. Weisman, on behalf of EPCOR, further noted that a slowdown in the economy would reduce the I factor and therefore the K-bar trajectory. Mr. Eck, on behalf of Fortis, noted that growth programs are externally driven and based on the obligation to serve and that, as a result, Fortis considers its customer growth program to fall into the Type 1 category.[242]

194. Regarding short life assets, Dr. Lowry, on behalf of the CCA, expressed his view that short-cycle capital additions should never be considered for incremental capital funding as there is a lot of opportunity to game the system. For example, a distribution utility could replace a large number of short-term assets, such as vehicles, at the end of the current generation PBR plans which would generate a revenue surplus through the next generation PBR plans when the distribution utility avoids replacing its short-term assets. Mr. Baraniecki, on behalf of EPCOR, noted that one of the issues resulting in the requirement for incremental capital funding is that by the time you replace a long-term asset, there has been 40 years of accumulating inflation and the depreciation related to that asset is not enough to fund the replacement. He explained that this is not an issue for short-term assets, such as tools, and noted that a distribution utility should be able to manage these very short-lived assets under the I-X mechanism.[243]

195. Regarding replacement capital, Dr. Lowry, on behalf of the CCA, expressed that replacement capital additions should be included under the Type 2 capital mechanism as the distribution utility has considerable discretion in the timing of these capital additions and this type of expenditure is more under the distribution utility’s control than other capital additions.[244]

196. The Commission agrees with those parties supporting a division of incremental capital funding into two types. In accepting the division of capital into two types, the Commission understands Dr. Weisman’s view that it is not optimal to manage certain programs under a Type 2 capital mechanism because a Type 2 approach might cause an undue level of risk to be imposed on the distribution utility because of the nature of certain programs. However, while acknowledging the concern with respect to risk if all programs were to be included in the Type 2 category, the Commission also shares the concern of interveners that it is possible for too much capital to be subject to Type 1 treatment, reducing the overall incentive properties of PBR,

241 Transcript, Volume 2, page 317, lines 17-24 (Dr. Brown); Transcript, Volume 15, page 3085, line 22 to page 3086, line 7 (Dr. Weisman).

242 Transcript, Volume 11, page 2244, line 25 to page 2245, line 3 (Dr. Lowry); Transcript, Volume 13, page 2572, lines 8-11 (Mr. Baraniecki); Transcript, Volume 14, page 3025, line 15 to page 3026, line 14 (Mr. Baraniecki); Transcript, Volume 14, page 3026, lines 16-20 (Dr. Weisman); Transcript, Volume 9, page 1780, line 25 to page 1781, line 13 (Mr. Eck).

243 Transcript, Volume 11, page 2143, lines 6-11 and page 2244, lines 12-24 (Dr. Lowry); Transcript, Volume 15, page 3062, line 19 to page 3063, line 17 (Mr. Baraniecki).

244 Transcript, Volume 9, page 1867, lines 12-18 (Dr. Lowry).

assuming Type 1 projects and programs continue to be managed under the current capital tracker mechanism. Based on the Commission's experience with administering capital trackers during the 2013-2017 PBR plans, the Commission considers that as much incremental capital funding as possible should be managed under the Type 2 capital mechanism during the next generation PBR plans. The Commission has learned that the distribution utilities have considerable flexibility in dealing with the timing of their capital programs and are capable of accommodating many changes in circumstances without any immediate concerns about service quality and meeting their obligation to serve. Accordingly, the Commission will define a narrow criteria for Type 1 capital, and all other capital will be defined as Type 2 capital. This approach to the separation of capital will increase regulatory efficiency by reducing the number of regulatory proceedings to approve and potentially true up capital tracker projects and programs, and it will ensure that the vast majority of capital will be subject to the superior incentive properties of PBR.

197. The Commission's approach to defining the Type 1 capital tracker criteria is to determine whether there is a type of capital that does not meet the criteria for Z factors but is not a type of capital that the distribution utilities have deployed in the past. These types of capital additions might include capital additions required by new government programs not previously experienced but would not include types of expenditures required by governments in the normal course of expectations, such as moves required to accommodate road or interchange reconfigurations. Growth, short-lived assets and replacement projects or programs would also be included in Type 2 because they have been experienced in the past. At the time of the rebasing application, any capital that is included in historical rate base will be included as a Type 2 project in the calculation of base K-bar. As a result, there will be no Type 1 capital programs included in going-in rates for the next generation PBR plans. Over the course of the term, if any new projects or programs arise, the Commission will assess these new projects or programs against the Type 1 criteria to determine if they qualify for Type 1 capital tracker treatment.

198. Based on the foregoing, the Commission adopts the following criteria for Type 1 capital trackers, which replace the original capital tracker criteria established in Decision 2013-435:

(i) The project must be of a type that is extraordinary and not previously included in the distribution utility's rate base.

(ii) The project must be required by a third party.

199. The Commission considers that the distribution utility requesting a program to qualify for Type 1 capital tracker treatment must demonstrate that both of the criteria have been satisfied.

200. Based on the recommendations of both Brattle and EPCOR,[245] the Commission will not allow the movement of capital projects or programs from one category to another. Once a type of capital is in Type 2, it will remain in Type 2 throughout the PBR term. Similarly, a type of capital found to be Type 1 will not be moved into Type 2 during the PBR term.

201. The following subsections establish the parameters for Type 1 and Type 2 incremental capital funding.

[245] Transcript, Volume 4, page 556, lines 9-13 (Mr. Brown); Transcript, Volume 4, page 556, lines 18-21, and page 557, lines 7-12 (Dr. Carpenter); Transcript, Volume 13, page 2580, lines 13-16 and page 2753, lines 14-18 (Mr. Baraniecki); Transcript, Volume 15, page 3122, lines 20-25 (Dr. Weisman).

6.4 Proposed capital mechanisms

202. A number of capital mechanisms have been proposed by parties to this proceeding, which are discussed in this section.

203. Multiple proposals advanced by parties involved an initial forecast for capital without a true-up component in order to enhance the incentives on capital. Brattle's Type 2 modified K factor proposal would require a distribution utility to forecast its K factor for Type 2 capital on a biannual basis. Brattle also put forward for consideration an F factor proposal that would apply to certain programs that could be forecast for the full five-year PBR term. Neither of these approaches proposed by Brattle would be subject to a true-up.[246] The ATCO utilities, Fortis, ENMAX, and AltaGas supported Brattle's modified K factor proposal,[247] but no parties supported Brattle's F factor proposal. Capital trackers with limited prospective-only true-ups was proposed by EPCOR. Under this approach, forecast capital tracker amounts would not be subsequently trued up for the period of time between the approval of the forecast and the approval of the true-up. However, a prospective true-up would be permitted. Rate base for years later in the PBR term that are eligible to have an updated forecast would be updated to reflect actual capital additions for PBR term years that had already passed, beginning only at the time the revised forecast and true-up is approved.[248] While EPCOR proposed this mechanism, it was not EPCOR's preferred mechanism[249] and no other parties to this proceeding supported this mechanism.

204. Dr. Lowry, on behalf of the CCA, noted that while eliminating the true-up creates stronger incentives for the distribution utility to control costs, it also creates the opportunity for the distribution utility to benefit from exaggerating its forecasts and puts more pressure on the Commission to ensure the forecasts are reasonable.[250] The UCA and Calgary also expressed concerns associated with over-forecasting, gaming, and information asymmetry.[251] The Commission agrees with the concerns about over-forecasting and asymmetrical information and finds that an incremental capital mechanism that includes a forecasting component but lacks a true-up is problematic because it incorporates the unacceptable forecasting incentives present under COS regulation and acknowledged by the interveners and Dr. Weisman. For these reasons, the Commission does not approve Brattle's Type 2 modified K factor, Brattle's F factor or EPCOR's proposal for capital trackers with limited prospective-only true-ups.

205. Calgary and Mr. Thygesen, on behalf of the CCA, argued for the elimination of all capital trackers and a simple I-X treatment.[252] The CCA and the UCA both suggested that the capital tracker mechanism had been expanded beyond the original intentions of the Commission as set out in Decision 2012-237. Mr. Bell, on behalf of the UCA, submitted that capital trackers dull

246 Exhibit 20414-X0056, Brattle written evidence, PDF pages 50-51, Q/A 91.
247 Exhibit 20414-X0070, ATCO utilities PBR plan proposal, paragraph 57; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraph 111; Exhibit 0414-X0069, ENMAX PBR plan proposal, paragraph 54; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 91.
248 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 149; Exhibit 20414-X0074, EPCOR PBR plan proposal, Appendix A, Evidence of Dr. Weisman, paragraph 96.
249 Exhibit 20414-X0623, EPCOR argument, paragraph 19.
250 Transcript, Volume 11, page 2157, line 12 to page 2158, line 15 (Dr. Lowry).
251 Exhibit 20414-X0618, UCA argument, paragraph 109; Exhibit 20414-X0184, UCA-AUC-2016APR15-004; Exhibit 20414-X0625, Calgary argument, paragraph 147.
252 Exhibit 20414-X0071, Calgary PBR plan proposal, PDF pages 12 and 62; Exhibit 20414-X0457, PARTIES[Calgary]-AUC-2016JUN03-015 and PARTIES[Calgary]-AUC-2016JUN03-019; Exhibit 20414-X0238, CALGARY-AUC-2016APR15-003(c); Transcript, Volume 10, page 2038, lines 4-5 (Mr. Thygesen).

the incentives of the PBR regime by removing the possibility of scarcity. He did, however, acknowledge that some form of capital relief may be required in some circumstances. In argument, the UCA submitted that next generation PBR plans should include a strict set of criteria for capital tracker treatment eligibility designed to ensure that only truly idiosyncratic projects or programs would qualify for incremental capital funding.[253] The UCA further noted that a project could only be considered truly idiosyncratic if "by its nature or its scope" it is not reflected in going-in rates, meaning that an ongoing project with a consistent unit rate of output should not be considered for capital tracker treatment, regardless of the result of the accounting test.[254] Dr. Lowry, on behalf of the CCA, argued for capital relief only in very limited circumstances. In argument, the CCA acknowledged that some form of capital relief was likely necessary, but favoured stringent provisions for incremental capital funding.[255]

206. By contrast, the distribution utilities submitted that pure I-X funding would not provide a sufficient opportunity to recover costs.[256] Dr. Weisman, on behalf of EPCOR, and Dr. Carpenter, of Brattle, argued that the incentives for efficiency are stronger in a PBR plan that has some allowance for capital additions when compared to pure I-X because operating at or near to the reopener provision could incent distribution utilities towards inefficient behaviours.[257] The distribution utilities also disagreed that the scope of capital trackers should be limited in the manner described by the UCA and the CCA. The ATCO utilities, ENMAX, and AltaGas argued that the capital tracker funding mechanism, as applied in the 2013-2017 PBR plans, had not strayed from the original intentions as described in Decision 2012-237.[258] Additionally, Fortis, EPCOR, and AltaGas submitted that limiting incremental capital funding beyond the principles already established would not provide a reasonable opportunity to recover prudently incurred costs.[259] The distribution utilities and their expert witnesses recommend the continued use of capital trackers as the capital mechanism for Type 1 capital.[260]

207. The K-bar mechanism, as proposed by EPCOR and Fortis with some differences, would add incremental capital funding where the I-X mechanism cannot. Under this proposal, an initial amount, referred to as the base K-bar, would be established as the incremental capital funding for all Type 2 capital in 2018. The base K-bar would be calculated by using an accounting test similar in concept to the test used during the 2013-2017 PBR term. EPCOR also proposed that the test would be applied to all Type 2 capital, not just Type 2 capital qualifying for capital tracker treatment. This amount would be determined as a part of the rebasing proceeding and

253 Transcript, Volume 16, page 3400, lines 17-25 and page 3405, lines 5-14 (Mr. Bell).
254 Exhibit 20414-X0618, UCA argument, paragraphs 95-96; Transcript, Volume 16, page 3446, lines 6-14 (Mr. Bell).
255 Transcript, Volume 11, page 2178, lines 19-21 (Dr. Lowry); Exhibit 20414-X0630, CCA argument, paragraph 15.
256 Exhibit 20414-X0616, AltaGas argument, paragraph 77; Exhibit 20414-X0619, ENMAX argument, paragraph 96; Exhibit 20414-X0622, ATCO argument, paragraph 72; Exhibit 20414-X0623, EPCOR argument, paragraph 109; Exhibit 20414-X0624, Fortis argument, paragraph 89.
257 Transcript, Volume 13, page 2610, line 19 to page 2611, line 13 (Dr. Weisman); Transcript, Volume 1, page 125, lines 7-12 and line 15 (Dr. Carpenter).
258 Exhibit 20414-X0637, ATCO reply argument, paragraph 104; Exhibit 20414-X0634, ENMAX reply argument, paragraphs 79-80; Exhibit 20414-X0639, AltaGas reply argument, paragraphs 32-34.
259 Exhibit 20414-X0633, Fortis reply argument, paragraph 44; 20414-X0635, EPCOR reply argument, paragraph 96; Exhibit 20414-X0639, AltaGas reply argument, paragraphs 32-34.
260 Exhibit 20414-X0056, Brattle written evidence, PDF pages 50-51, Q/A 91; Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraphs 52-54; Exhibit 20414-X0070, ATCO PBR plan proposal, paragraphs 57-59; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 70 and 95; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 125; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 90.

then escalated throughout the next generation PBR plans using an approved calculation methodology to determine the level of incremental capital funding in each year during the 2019-2022 period. Capital funded under the K-bar mechanism would not be trued up during the next generation PBR plans.[261]

208. In addition to his preferred position of limiting capital tracker availability, Mr. Bell, on behalf of the UCA, proposed the use of a building blocks model PBR plan based on what is approved for FortisBC Inc. in British Columbia.[262] Mr. Bell explained that this version of building blocks starts with base capital and base O&M revenues and then adjusts the revenues by I-X and a growth factor to generate the revenue for each year. Base O&M and base capital amounts are determined from past actual amounts which are adjusted to arrive at the opening figures.[263] Mr. Bell noted that K-bar and the building blocks model are similar.[264] The building blocks model is not the preferred approach of any party on this record, as it was proposed as an option by Mr. Bell and supported by the UCA in argument as its third choice after a return to COS regulation.[265]

209. The Commission considers that adopting a FortisBC type of building blocks model for the next generation PBR plans would involve changes to many elements of the plan other than just the treatment of capital and is out of scope of this proceeding. The Commission notes that Mr. Bell suggested the adoption of a building blocks approach only if incremental capital funding was required but did not expand upon what other adjustments to the PBR plan would be required as a result.[266] Further, a consideration of possible adoption of one component of a another jurisdiction's PBR plan would necessitate an understanding of the various other elements of the plan and the potential impacts of these changes to Alberta's PBR plans. For these reasons, the Commission does not approve Mr. Bell's building blocks model.

210. In addition to the mechanisms for the treatment of capital that have been described above, parties to this proceeding also considered a menu approach whereby multiple capital mechanisms are available with the distribution utilities being able to choose their preferred mechanism for incremental capital funding. While a number of advantages to such an approach were identified by Brattle, Dr. Weisman, on behalf of EPCOR, and Dr. Lowry, on behalf of the CCA, there were also a number of concerns identified regarding the challenges associated with building and understanding the menu. Some of these challenges involved a number of issues and plan design components that are outside of the scope of this proceeding, such as earnings sharing mechanisms or changes to the reopener parameters.[267] The UCA additionally expressed concern that there would be complexities associated with ensuring the menu approach was designed in a manner consistent with PBR principle 5, permitting benefits to be shared.[268] The Commission

261 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 126-129 and 135-136; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 107-110.

262 Exhibit 20414-X0187, UCA-AUC-2016APR15-007(e), Attachment 1, FortisBC EnergyInc. Multi-Year Performance Based Ratemaking Plan for 2014 through 2018.

263 Transcript, Volume 17, page 3620, lines 1-14 (Mr. Bell); Exhibit 20414-X0187, UCA-AUC-2016APR15-007(e), Attachment 1, FortisBC EnergyInc. Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, page (iv), PDF page 11.

264 Transcript, Volume 17, page 3606, lines 2-6 (Mr. Bell); Exhibit 20414-X0618, UCA argument, paragraph 106.

265 Exhibit 20414-X0618, UCA argument, paragraph 106.

266 Exhibit 20414-X0066, UCA evidence of Mr. Bell, PDF pages 33-34.

267 Exhibit 20414-X0173, BRATTLE-AUC-2016APR15-021; Exhibit 20414-X0256, EDTI-AUC-2016APR15-028; Exhibit 20414-X0408, CCA rebuttal evidence of Dr. Lowry, PDF pages 80-81.

268 Exhibit 20414-X0184, UCA-AUC-2016APR15-010.

agrees that a menu approach could impact elements of the PBR plan that are outside the scope of this proceeding and adds additional complications in ensuring that each of the PBR principles are addressed. Accordingly, a menu approach to capital will not be considered at this time in connection with establishing the next generation PBR plans.

211. Consistent with the findings in Decision 2012-237, the Commission agrees with parties that the incentives under I-X for a distribution utility to seek efficiency improvements in its capital spending are stronger than the incentives associated with capital tracker programs.[269] Accordingly, excluding a large portion of a distribution utility's capital additions from the I-X mechanism would have the effect of significantly dampening the efficiency incentives intended by a PBR plan. Both the proposals for an amended pure I-X and K-bar applied to Type 2 capital have the effect of minimizing the capital additions that will be managed outside of the I-X mechanism. However, K-bar is able to provide incremental capital funding for programs that fail the Type 1 criteria while maintaining strong incentives for efficiency whereas the amended pure I-X proposal would provide incremental capital funding on an extremely restricted basis.

212. In a comparison of pure I-X and K-bar, Dr. Weisman, on behalf of EPCOR, explained that when the revenue sufficiency condition under pure I-X is uncertain, as he expects would be the case in the next generation PBR plans, the incentives for efficiency are actually stronger under K-bar than they would be under pure I-X. He explained that this occurs because the incentives with respect to minimizing costs under I-X apply equally to the costs under K-bar, but K-bar also has the advantage of reducing the risk of triggering a reopener due to insufficient funding.[270] Parties noted that K-bar would result in a reduction in regulatory burden and Mr. Retnanandan, on behalf of AltaGas, also noted that K-bar has the benefits of providing a certain degree of rate stability.[271]

213. While EPCOR was the only party that preferred a K-bar for Type 2 capital, many parties to this proceeding supported K-bar as an option, preferring it over some of the other proposed alternatives.[272] Only ENMAX directly opposed K-bar, arguing that it would not provide a reasonable opportunity to recover costs as historical costs would not necessarily align with future costs.[273] Other distribution utilities and Brattle shared the concern that K-bar could result in an amount of funding different from what a distribution utility would require.[274]

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269 Decision 2012-237, paragraph 574; Transcript, Volume 4, page 560, lines 19-24 (Dr. Brown); Transcript, Volume 10, page 2013, lines 9-16 (Dr. Lowry); Transcript, Volume 14, page 3019, line 21 to page 3020, line 2 (Dr. Weisman).

270 Transcript, Volume 13, page 2610, line 19 to page 2611, line 13 (Dr. Weisman).

271 Transcript, Volume 15, page 3076, line 16 to page 3077, line 21 (Mr. Baraniecki); Exhibit 20414-X0073, Fortis PBR plan proposal, paragraph 109; Transcript, Volume 5, page 902, lines 16-22 (Mr. Retnanandan).

272 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 124; Transcript, Volume 5, page 903, line 6 to page 904, line 1 (Mr. Johnston); Transcript, Volume 7, page 1420, line 24 to page 1421, line 5 (Ms. Bayley); Exhibit 20414-X0618, UCA argument, paragraph 106; Exhibit 20414-X0638, CCA reply argument, paragraphs 38-39; Exhibit 20414-X0636, Calgary reply argument, paragraph 183; Exhibit 20414-X0624, Fortis argument, paragraphs 123 and 128.

273 Exhibit 20414-X0619, ENMAX argument, paragraph 110.

274 Transcript, Volume 6, page 1224, lines 14-21 (Mr. Howell); Exhibit 20414-X0616, AltaGas argument, paragraph 74; Exhibit 20414-X0624, Fortis argument, paragraph 128; Exhibit 20414-X0449, PARTIES(Brattle)-AUC-2016JUN03-009; Exhibit 20414-X0455, Parties(ENMAX)-AUC-2016JUN03-009; Exhibit 20414-X0454, PARTIES(ATCO)-AUC-2016JUN03-009; Transcript, Volume 4, page 580, line 22 to page 582, line 6 (Dr. Brown).

214. The Commission considers that any choice of the capital mechanism will result in trade-offs. The Commission accepts that there is considerable benefit to the distribution utility and to customers to ensuring that the same high-powered incentives present under the I-X mechanism apply to capital. A K-bar approach maximizes the ability of each distribution utility to manage its business and to discover and pursue efficiencies and costs saving by providing flexibility in how it plans and allocates capital funding throughout the next generation PBR plans while fulfilling its obligation to serve. This increased flexibility and reduced regulatory burden is preferable to the present annual capital tracker forecast, approval and true-up mechanism for all incremental capital requirements. The Commission further considers that an amended pure I-X proposal, which only allows for restricted access to incremental capital funding, may be insufficient to provide the incremental capital funding for necessary capital additions given that the distribution utilities were able to demonstrate under existing capital tracker criteria that incremental capital funding was required to allow the distribution utilities to fund necessary capital additions under the 2013-2017 PBR plans. The Commission recognizes the concerns of the interveners that rates of return seemed high in the 2013-2017 PBR term. As noted above, the Commission is not convinced that the earnings were high primarily because of capital trackers. As the Commission has discussed previously, the level of going-in rates for 2012, established under the traditional rate base rate of return regulation, was a significant contributor to earnings levels. The Commission has discussed its approach to establishing going-in rates for the next generation PBR plans in Section 4 above. The significance of the capital tracker program was that its operation had the unintended effect of removing considerable capital from the productivity incentives created by the I-X mechanism.

215. For the reasons given, the Commission approves a continuation of capital trackers as the capital funding mechanism for Type 1 projects and programs during the next generation PBR plans. As discussed above, the Commission has defined narrow criteria for Type 1 capital trackers thereby eliminating many of the concerns with the 2013-2017 PBR plans' capital trackers. All other capital will be dealt with under a K-bar approach. Decisions on the details and calculation of these two mechanisms can be found in sections 6.4.2 and 6.4.3.

216. Given the approval of two categories for capital, Type 1 and Type 2, the next generation PBR plans will include two separate factors for capital. In any given year, the total K factor amount will be the sum of the approved capital tracker funding for Type 1 programs. The total K-bar factor will be the amount of K-bar funding for Type 2 programs.

6.4.1 Negative accounting test results

217. In Decision 2013-435, the Commission addressed the issue of negative results when the accounting test is applied to capital projects and programs. Certain parties had argued that negative accounting test results for a capital project demonstrated that the revenue generated under the I-X mechanism is more than is required to fund the revenue requirement for the project. This revenue surplus could be applied to offset all or portions of the revenue requirement for capital projects and programs that had positive accounting test results. The result of this approach would be an overall reduction in the incremental capital funding required through capital trackers. In dismissing this suggestion, the Commission stated:

> … any reduction in capital spending on projects funded under the I-X mechanism are to be retained by the company to preserve the incentive to seek productivity gains under

> PBR. If a company were required to return any savings resulting from productivity gains, it would have an adverse effect on the incentive properties of PBR.[275]

218. In its June 27, 2016 letter, the Commission noted that negative accounting test results can arise from causes other than productivity gains. For example, a negative accounting test result can occur when the distribution utility receives return and depreciation expense revenues under the I-X mechanism in respect of a particular project greater than the actual revenue requirement for the project. The Commission also noted that it is difficult for outside parties to determine the reason for a negative accounting test result, simply by observing such a result.[276] For this reason, the Commission indicated to parties that it intended to explore negative accounting test results during the oral hearing.

219. During the oral hearing, in addition to maintaining the present treatment of negative accounting results, several proposals for offsetting in whole or in part negative accounting results against positive accounting test results were explored. AltaGas, EPCOR, the ATCO utilities, and Fortis all noted that the materiality threshold will be recalculated at the time of rebasing, which will naturally have the effect of increasing the materiality thresholds.[277] Mr. Bell, on behalf of the UCA, suggested that the increase proposed by the distribution utilities would be inadequate and, therefore, proposed making the materiality threshold cumulative.[278] Ms. Sullivan, on behalf of Fortis, also proposed a larger year-over-year increase to the materiality threshold throughout the term, noting that growth in rate base is larger than I-X, the current escalation factor.[279] The CCA considered that a combination of higher materiality thresholds and "dead zones," which would require the distribution utility to absorb a percentage of the capital costs of a project before it would qualify for capital tracker funding for the amount in excess of the dead zone amount, would strengthen the performance incentives.[280]

220. In its reply argument, AltaGas proposed that the Commission may want to consider assessing the timing of capital additions subject to capital trackers to prevent an artificial build-up of costs to achieve capital tracker eligibility, and to ensure that the timing of spending is reasonable for the proposed program and associated asset categories. It also considered that projects and programs that fail the materiality test part way through the term should remain within the capital tracker "pool" until the time of rebasing.[281]

221. Mr. Baraniecki noted that EPCOR's K-bar Type 2 capital proposal addresses the negative accounting test result issue because the base K-bar would be calculated as the net amount or sum of all accounting test outputs for K-bar Type 2 capital programs. This would include positive amounts above the current materiality threshold, positive amounts below the materiality threshold, and negative amounts, often referred to by the CCA as "negative capital trackers." EPCOR also noted that there is no reason why the base K-bar amount could not be negative. The CCA, the UCA, and Calgary also commented that a plan that nets out the positive and

275 Decision 2013-435, paragraph 965.
276 Exhibit 20414-X0485 AUC letter - Oral hearing preliminary matters, paragraph 2(a).
277 Transcript, Volume 7, page 1437, lines 13-21 (Ms. Berger); Exhibit 20414-X0256, EDTI-AUC-2016APR15-027; Exhibit 20414-X0289, AUI-AUC-2016APR15-010; Exhibit 20414-X0183, FAI-AUC-2016APR15-017.
278 Transcript, Volume 17, page 3603, line 16 to page 3604, line 3 and page 3613, lines 4-17 (Mr. Bell).
279 Transcript, Volume 9, page 1818, line 25 to page 1819, line 19 (Ms. Sullivan).
280 Exhibit 20414-X0630, CCA argument, paragraph 19.
281 Exhibit 20414-X0639, AltaGas argument, paragraph 54.

negative amounts would solve the issue.[282] Mr. Baraniecki also commented that the negative and positive accounting test results for Type 1 capital could also be netted. He indicated that the accounting test results for Type 1 capital would only turn negative as an outcome of the math if capital additions have dropped off. Therefore, netting of positive and negative accounting tests for Type 1 capital would not have a negative impact on incentives.[283]

222. Fortis did not propose to net positive and negative accounting test results in its proposed version of the K-bar Type 2 capital funding mechanism. Ms. Sullivan explained that this is because Fortis' proposal continued the practice that only programs that passed the existing capital tracker criteria would qualify for capital treatment, consistent with the 2013-2017 PBR plans. In argument, Fortis further noted that most of its negative accounting test results relate to productivity improvements and that it is important to preserve incentives for distribution utilities to continue to seek productivity improvements. Mr. Howell, on behalf of the ATCO utilities, noted that if the accounting test results for capital programs are netted, the Commission would have to test all of the capital, rather than just a subset to ensure the prudence of all expenditures, resulting in increased regulatory burden.[284]

223. The Commission considers that netting the positive and negative accounting test results is warranted in moving to a K-bar funding mechanism for incremental capital requirements for Type 2 capital. The Commission finding in Decision 2013-435, that requiring a distribution utility to return savings resulting from productivity gains would have an adverse effect on the incentive properties of PBR, does not apply to the K-bar approach to incremental capital funding of Type 2 capital. The negative effect on the incentive properties of PBR identified in Decision 2013-435 arises if a distribution utility were to be required to return savings gained through productivity improvements after the savings have been realized. As noted by Dr. Brown, of Brattle, and Dr. Weisman, on behalf of EPCOR, because the K-bar mechanism does not include a true-up, netting the positive and negative accounting test results in establishing a base K-bar will not have an adverse effect on the incentive properties of PBR.[285] Eliminating capital reviews during the PBR term by using the K-bar approach also addresses the issue of testing the entire capital program which was identified by Mr. Howell, on behalf of the ATCO utilities. For these reasons, the Commission finds that positive and negative accounting test results for Type 2 capital should be netted in the calculation of the base K-bar.

224. With respect to the issue of netting Type 1 capital projects and programs, the Commission observes that the criteria established for Type 1 capital will make it unlikely that a Type 1 program will have negative accounting test results.

[282] Transcript, Volume 13, page 2709, lines 20-21 and page 2577, line 18 to page 2579, line 5 (Mr. Baraniecki); Transcript, Volume 15, page 3114, lines 12-15 and page 3165, line 17 to page 3166, line 16 (Mr. Baraniecki); Exhibit 20414-X0079, EPCOR Schedule 5; Exhibit 20414-X0080, EPCOR, Schedule 6; Transcript, Volume 10, page 1933, lines 20-24 (Mr. Thygesen); Transcript, Volume 11, page 2226, line 23 to page 2227, line 5 (Dr. Lowry); Transcript, Volume 16, page 3336, lines 2-11 (Mr. Matwichuk); Transcript, Volume 17, page 3611, lines 10-17 (Mr. Bell).

[283] Transcript, Volume 13, page 2733, lines 15-22 (Mr. Baraniecki); Transcript, Volume 15, page 3088, lines 4-24 (Mr. Baraniecki); Transcript, Volume 15, page 3118, lines 5-15 (Dr. Weisman); Exhibit 20414-X0623, EPCOR argument, paragraph 93.

[284] Exhibit 20414-X0453, PARTIES(FAI)-AUC-2016JUN03-009; Transcript Volume 9, page 1654, lines 6-14 (Ms. Sullivan); Exhibit 20414-X0624, Fortis argument, paragraph 133; Transcript, Volume 7, page 1441, lines 13-18 (Mr. Howell).

[285] Transcript, Volume 4, page 623, lines 8-15 and page 625, lines 1-6 (Dr. Brown); Transcript, Volume 13, page 2736, line 22 to page 2737, line 1 (Dr. Weisman).

225. In this section of the decision, the Commission has determined that capital additions for each distribution utility will be managed in one of two categories, Type 1 or Type 2. Further, given the changes to the treatment of supplement capital tracker funding for the next generation PBR plans, the capital tracker criteria established in Decision 2012-237 and refined in Decision 2013-435 will no longer apply to Type 1 capital under the next generation PBR plans. The Type 1 criteria is defined in Section 6.3 and details of the Type 1 capital mechanism will be reviewed in Section 6.4.2.

226. In this subsection, the Commission has determined that the positive and negative accounting test results for Type 2 capital will be netted in determining the base K-bar. Given this change to the treatment of supplement capital funding for the next generation PBR plans, the capital tracker criteria established in Decision 2012-237 and refined in Decision 2013-435 will no longer apply to Type 2 capital under the next generation PBR plans. Details of the Type 2 capital mechanism are discussed in Section 6.4.3.

6.4.2 Type 1 capital mechanism: capital trackers

227. This section will outline the details of the Type 1 capital tracker mechanism in the next generation PBR plans.

228. The Type 1 capital tracker mechanism in the next generation PBR plans will continue to rely on the accounting test similar to the accounting test utilized by the distribution utilities during the 2013-2017 PBR plans to determine the amount of K factor funding. The tier 2 materiality thresholds that were incorporated in the accounting tests used during the 2013-2017 PBR plans are no longer applicable. However, the tier 1 materiality threshold will continue to apply at the program level for Type 1 capital trackers. There are also other consequential or incremental modifications to the calculation of the accounting test. These modifications are discussed below.

229. One of the items listed on the final issues list with respect to the current capital tracker mechanism was the possibility of eliminating the availability of Commission approval on a forecast basis for capital tracker expenditures. Elimination of this forecast approval process would require the distribution utilities to undertake the investment prior to applying for recovery of their costs by way of a capital tracker.[286] AltaGas and EPCOR commented that requiring a distribution utility to apply for capital trackers after the fact would result in cash flow concerns, weaken the distribution utilities' credit metrics, and increase the cost of capital as financial markets react to the increased risk of disallowance. Dr. Weisman, on behalf of EPCOR, also noted that eliminating the forecast could result in an increased cost of capital if financial markets perceive a greater risk of disallowance. Dr. Brown, of Brattle, stated that the advantage of providing a forecast is that the Commission and parties have an opportunity to test whether the project meets the capital tracker criteria, which gives the distribution utility comfort going forward that it is spending money on programs that will qualify for incremental capital funding. The ATCO utilities agreed with this position in its argument. AltaGas and EPCOR further commented that a utility would be incented to postpone capital projects or programs in the absence of allowing a forecast to be made and approved, potentially running assets to failure, because the distribution utility would not have assurance that the Commission would ultimately allow the distribution utility to recover its costs. Mr. Baraniecki, on behalf of EPCOR, also stated that while it is difficult for a corporation to do a project without knowledge that it will be

[286] Exhibit 20414-X0026, AUC letter - Final issues list, August 21, 2015, attachment, PDF pages 11-12.

allowed recovery of costs, that this problem is less of an issue "if it's already established that that project is going to be a capital tracker and that you will be allowed funding, it's just the amount of funding and it's really a prudency decision at the end."[287]

230. The Commission observes that the distribution utilities now have a number of years of experience with capital trackers and the Commission considers that parties should have an understanding of the types of expenditures that will be considered prudent by the Commission at the time of a true-up application. Further, the issue of a project subsequently failing any of the remaining criteria established in Decision 2012-237 in a particular year has been rendered moot. An after-the-fact decision during the true-up proceeding would be an assessment of the prudency of the costs, minimizing the concerns of EPCOR. The Commission does, however, note the cash flow issues, highlighted by AltaGas, that could occur if funding was not provided prior to the requirement for expenditures. In response to this concern, the possibility of replacing the forecast applications with a mechanical placeholder calculation was explored.

231. While it was not a part of AltaGas' initial proposal, in the hearing, Mr. Stock advocated for the use of a simple mechanical placeholder capital tracker amount over a forecast approval process. In argument, AltaGas proposed that the placeholder could be based on the last recorded actuals escalated by I-X, calculated using a two-year historical average of actual capital additions, or some other reasonable basis. Mr. Stock noted that there could be efficiencies to be gained by switching to this approach and noted that this type of placeholder calculation is the same as what is currently approved as the forecast methodology for some capital tracker programs, including AltaGas' gas supply program.[288]

232. Ms. Mosley commented that it is ENMAX's preference to use forecasts as they provide the most accurate information. Ms. Sullivan, on behalf of Fortis, and Mr. Baraniecki, on behalf of EPCOR, commented that due to the volatility of Type 1 programs, a placeholder based on historical averages will not result in the correct amount. The UCA, and Mr. Thygesen, on behalf of the CCA, expressed concern with eliminating the forecast component because in their view, there have been few cost denials in Alberta once expenditure has been made, noting that it would be preferable to have the controls up front. However, in argument, the UCA also noted that elimination of forecasts for capital trackers may merit consideration.[289]

233. The Commission considers that replacing the capital tracker forecast applications with a placeholder amount for Type 1 capital tracker programs has the ability to reduce regulatory burden, which the Commission considers to be desirable consistent with PBR principle 2. For this reason, the Commission considers that there is merit in including a readily determinable placeholder in the annual PBR rate adjustment filings in respect of the net revenue requirement

287 Exhibit 20414-X0289, AUI-AUC-2016APR15-007; Exhibit 20414-X0256, EDTI-AUC-2016APR15-017; Exhibit 20414-X0623, EPCOR argument, paragraph 106; Transcript, Volume 15, page 3094, line 10 to page 3095, line 3 (Dr. Weisman); Transcript, Volume 4, page 571, lines 16-24 (Dr. Brown); Exhibit 20414-X0622, ATCO argument, paragraph 115; Transcript, Volume 15, page 3095, line 16 to page 3096, line 18 (Mr. Baraniecki).

288 Transcript, Volume 5, page 882, line 23 to page 886, line 6 and page 923, lines 11-17 (Mr. Stock); Exhibit 20414-X0616, AltaGas argument, paragraph 53.

289 Transcript, Volume 8, page 1537, lines 5-12 (Ms. Mosley); Transcript, Volume 9, page 1783, line 14 to page 1784, line 10 (Ms. Sullivan); Exhibit 20414-X0624, Fortis argument, paragraph 107; Transcript, Volume 15, page 3097, lines 1-18 (Mr. Baraniecki); Exhibit 20414-X0184, UCA-AUC-2016APR15-005; Exhibit 20414-X0084, CCA evidence of Mr. Thygesen, PDF page 71; Exhibit 20414-X0618, UCA argument, paragraph 112.

for Type 1 capital trackers in the following year. Therefore, the Commission approves the elimination of the Type 1 capital tracker forecast applications.

234. Given the Type 1 criteria, the Commission notes that a distribution utility will be unable to calculate an inflation adjusted average of actual capital additions, as proposed by some parties. Accordingly, the Commission will accept an officer's certificate from the distribution utility showing the internal approved forecast associated with the Type 1 capital tracker project in the upcoming year. The placeholder for Type 1 projects or programs will be calculated as 90 per cent of the management-approved internal forecast for that year. This forecast will not be tested for reasonableness because the amounts will be subject to a true-up. The prudence of the costs associated with this project will be tested in the Type 1 capital tracker true-up application.

235. During the 2013-2017 PBR plans, capital tracker true-up applications included a discussion of the variance between the approved capital tracker forecast and the actual costs, which was used as one of the tools for parties to assess the prudence of the true-up amounts. Distribution utilities will no longer have a Commission-approved forecast that was assessed for reasonableness at the time of their true-up application; however, the Commission still finds value in receiving a variance explanation from the distribution utilities. The Commission directs the distribution utilities to prepare a variance analysis comparing the internal forecast, submitted during the application for the placeholder amount, to the actual costs. The Commission will utilize this information together with other supporting documentation with respect to the prudence of the expenditures (e.g., comparing actuals to trends in prior years or engineering studies provided by intervener groups questioning the costs) in determining prudence of the true-up amounts.

236. A second item listed on the final issues list, under considerations of modifications to the current capital tracker mechanism, was the possibility of eliminating or limiting the dollar 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.[290] Given the restriction of capital tracker treatment to Type 1 capital, the Commission does not consider a limitation to the ability to true up placeholder amounts to actual prudent expenditures to be warranted.

237. Some distribution utilities suggested that Type 1 capital projects or programs needed to be trued up annually, consistent with current capital tracker practices. Ms. Sullivan, on behalf of Fortis, explained that the high level of variability in year-over-year costs for Type 1 programs makes it difficult to move to a two-year true-up.[291]

238. AltaGas noted that longer time between true-ups could result in the accumulation of significant variances. Should the Commission favour a true-up proceeding every two years, AltaGas proposed biannual true-ups could be combined with an automatic interim rate adjustment (AIRA) which would be based on the untested additions reported in the relevant Rule 005 filing and would help with rate smoothing, limit intergenerational inequity, and minimize cash flow issues. AltaGas further proposed that if a distribution utility is expecting the true-up adjustments for two consecutive years to be going in opposite directions, then the

[290] Exhibit 20414-X0026, AUC letter - Final issues list, August 21, 2015, attachment, PDF pages 11-12.
[291] Transcript, Volume 6, page 1082, lines 16-18 (Mr. Howell); Transcript, Volume 9, page 1787, line 9 to page 1788, line 1 (Ms. Sullivan); Exhibit 20414-X0183, FAI-AUC-2016APR15-008; Exhibit 20414-X0157, EPC-AUC-2016APR15-007.

distribution utility would dispense with the AIRA at that point because of the expected offset in the second year.[292] AltaGas' AIRA is a possible solution to the issue of large variances accumulating between true-up applications, but the Commission is concerned that the proposal is at the option only of the distribution utility and that customers may not have sufficient information to request an AIRA adjustment.

239. Given that the Commission has decided that tested forecast applications will be replaced with placeholders based on untested internal forecasts, the Commission considers that annual true-up applications are warranted. Accordingly, the Commission finds that Type 1 capital trackers will be trued up annually during the next generation PBR plans. The distribution utilities will make applications each year seeking approval of the prior year capital tracker true-up shortly after the prior year actuals are known, with the idea that prior year true-up amounts can be included in the annual PBR rate adjustment filings made on or before September 10 each year. The upcoming year placeholder amount for Type 1 programs will be determined by the distribution utility and included in its annual PBR rate adjustment filings.

240. Regarding the minimum filing requirements for Type 1 capital trackers, the Commission will continue to expect that a distribution utility typically will be required to address the minimum filing requirements (MFRs) listed in Appendix 3 of Decision 3558-D01-2015. If amendments to the list of MFRs are necessary, then the Commission will consider such amendments as required, if there is sufficient evidence that the existing MFRs are not adequate. As noted in this section, in addition to the current MFRs, a distribution utility will be required to provide an officer's certificate showing the internal forecast associated with any new Type 1 capital tracker project in the annual PBR rate adjustment filings in order to qualify for a placeholder amount associated with that program, and a distribution utility will be required to provide its internal forecast associated with each Type 1 capital tracker project dated prior to the construction or implementation of the project in the true-up applications.

6.4.3 Type 2 capital mechanism: K-bar

241. Given the Commission's decision that Type 2 capital will be managed under the K-bar mechanism, this section will outline the details of the K-bar approach.

242. In general terms, which will be expanded upon in the remainder of this section, a base K-bar amount will be established for 2018 using an accounting test similar to the accounting test used during the 2013-2017 PBR plans but applied only to Type 2 capital projects and programs. The test will be calculated on a projected amount of rate base for 2018 for Type 2 capital, which will determine a capital funding shortfall or surplus for each program or project (i.e., positive or negative accounting test result). The accounting test results for Type 2 capital in 2018 will then be aggregated to determine the 2018 base K-bar amount. In subsequent years an additional amount of incremental K-bar funding is calculated by indexing the 2018 base K-bar amount by I-X.

[292] Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 91, 94-96; Transcript, Volume 5, page 934, lines 11-15; page 935, lines 3-10; page 937, lines 4-16 (Mr. Stock).

243. In Section 6.4.1, the Commission found that positive and negative accounting test results should be netted in the calculation of the base K-bar. An example of this calculation can be found in EPCOR's Schedule 5.[293]

244. With respect to how to calculate the 2018 Type 2 capital additions to be included in the base K-bar amount, multiple methods were proposed by parties:

- a five-year average of inflation-adjusted actuals;
- a three-year inflation-adjusted average using actuals for 2015-2016 and the Commission-approved forecast for 2017;
- a 2018 forecast; and
- a combined approach where some project expenditures are determined using a forecast while others are calculated using a formulaic approach based on historical averages.[294]

245. In discussing various proposals for dealing with incremental capital funding, the Commission rejected consideration of a capital mechanism based on forecasting component that lacked a true-up process. In rejecting the proposal, the Commission expressed concerns about the incentive for distribution utilities to over-forecast and asymmetrical information available to parties. For the same reasons, the Commission does not approve a method of calculating base K-bar that involves a forecast component. The Commission also agrees with those parties that took the position that using an average of historical actuals involves less regulatory burden than the testing of a full 2018 forecast for all capital programs.[295] Accordingly, the Commission will, instead, rely upon a formulaic approach to determine the 2018 projected capital additions to be included in the base K-bar accounting test.

246. Fortis proposed a formulaic approach in place of a forecast, using a three-year historical average to be consistent with the current capital tracker proceedings because a three-year historical average is a commonly accepted forecast methodology, and also because the multi-year approach provides assurance that both the early part of the term and the later part of the term are captured. EPCOR proposed using a five-year historical average. Mr. Baraniecki, on behalf of EPCOR, noted that some distribution utilities delayed capital additions in 2013 as a result of the uncertainty surrounding capital trackers. As a result, the capital additions in 2014 and 2015 may have been inflated with catch-up work, and an average that omits 2013 could result in an overinflated base K-bar. Further, a longer period would smooth out items such as customer growth and short-term asset expenditures, such as tools and vehicles, that may have significant year-over-year variations, but tend to average out to a reasonably stable average over their short life-cycle. Mr. Baraniecki also noted that capital additions have increased over the PBR term and if that trend continues during the next generation PBR plans, using a longer period of historical actuals to calculate the base K-bar will result in a more conservative base K-bar amount because older years would have lower levels than what would be expected to occur in the

293 Exhibit 20414-X0079, EPCOR Schedule 5, "3. 2018 F."

294 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 141-148; Exhibit 20414-X0183, FAI-AUC-2016APR15-012(b); Exhibit 20414-X0453, PARTIES(FAI)-AUC-2016JUN03-009(a); Exhibit 20414-X0458, PARTIES(AUI)-AUC-2016JUN03-009(c).

295 Exhibit 20414-X0453, PARTIES(FAI)-AUC-2016JUN03-009. Transcript, Volume 15, page 3104, lines 4-5 (Mr. Baraniecki).

future, resulting in a stretch factor on capital. For this reason, EPCOR would not propose an average or a period longer than five years.[296]

247. For the reasons provided by EPCOR, the Commission considers that the year 2013 should be included in the historical average. Additionally, because the capital additions associated with 2017 will occur after the release of this decision, the Commission considers including 2017 in the historical average will result in incentives to increase capital spending in 2017. Further, the Commission has previously determined that a four-year average of capital additions will be used to set the going-in rates for capital. Similarly, the Commission considers that the base K-bar should be determined as a four-year average of actual capital additions for the years 2013 through 2016. The Commission further notes that the distribution utilities were expected to be able to achieve productivity improvements in the amount of the X factor for the first term. As such, when determining the inflation adjusted amounts for each year, the Commission finds that the expenditures should be indexed by I-X, and not simply by the I factor, as proposed by parties.

248. The Commission notes that ENMAX was not on the same 2013-2017 PBR plans as the other distribution utilities. Using the same four-year average of 2013 through 2016 would include the last year of ENMAX's FBR term, its intervening COS year, and the first two years of its 2015-2017 PBR plan. The historical average determined for setting the base K-bar is intended to average the capital additions over the course of the PBR term without the perverse incentives apparent in the last year of a PBR term. Given this objective, the Commission considers a different time period for ENMAX is required in developing a base K-bar. In order to set an interim base K-bar for ENMAX using the same principles established for the other distribution utilities, the Commission considers that ENMAX's base K-bar should be calculated as a two-year average of actual capital additions for the years 2015 through 2016 in the manner calculated for the other distribution utilities and converted to 2017 dollars by indexing by the approved I-X for each year.

249. Regarding testing the amounts to be used in the average for prudence, the distribution utilities argued that capital additions during the 2013-2017 generation PBR plans do not need to be tested for prudence at rebasing as expenditures under I-X should be assumed to be prudent given the incentives for distribution utilities to deploy I-X capital in an efficient manner, and because expenditures under capital trackers during the 2013-2017 PBR plans have been already tested on a forecast or actual basis in the capital tracker process.[297]

250. Fortis proposed that the distribution utilities take an average of Rule 005 actual capital additions and that adjustments could be made to the base K-bar for any specific amounts that were determined to be imprudent during the capital tracker proceedings. EPCOR noted that Rule 005 does not contain sufficient detail to be used in the accounting test.[298]

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[296] Transcript, Volume 9, page 1806, line 5 to page 1807, line 2 (Ms. Sullivan); Exhibit 20414-X0624, Fortis argument, paragraphs 130-131; Transcript, Volume 15, page 3100, line 9 to page 3101, line 22 (Mr. Baraniecki).

[297] Transcript, Volume 13, page 2590, line 25 to page 2591, line 14 (Mr. Zurek); Exhibit 20414-X0255, ATCO-AUC-2016APR15-002(b).

[298] Transcript, Volume 9, page 1809, line 1 to page 1811, line 1 (Ms. Sullivan); Transcript, Volume 15, page 3102, line 14 to page 3103, line 15 (Mr. Baraniecki).

251. As noted in Section 4.2, the Commission agrees with the distribution utilities that non-capital tracker capital additions can generally be assumed to be prudent given the incentives for distribution utilities to deploy capital governed by the I-X mechanism in an efficient manner. Also consistent with the rebasing findings, the Commission considers that capital tracker capital has already been tested for prudence and, as such, no further testing or duplication of information would be required for previously approved actual costs for purposes of establishing the base K-bar. Due to the timing of the rebasing applications, parties will not have Commission-approved capital tracker trued-up actual amounts for 2016, and will use applied-for capital tracker actual costs consistent with their 2016 capital tracker true-up applications in their interim base K-bar calculation at the time of the rebasing applications. As 2016 is only one year in a four-year average, and the distribution utilities will be using actuals, the Commission expects any effect from the difference between applied-for actuals and Commission-approved actuals to be *de minimis* to the overall base K-bar. However, the Commission will require parties to submit a base K-bar adjustment correcting the 2016 actuals following the 2016 capital tracker true-up decisions.

252. Retirements are another contributing factor in the accounting test. They are important because the accounting test relies upon the revenue requirement resulting from the rate base for each capital category, and the rate base is calculated using historical additions, plus current year additions, less current year retirements, less accumulated depreciation. As a result, a projected level of retirements must be built into rate base used to calculate the 2017 notional rates, and a projected level of retirements must also be built into the 2018 projected rate base to be used for the 2018 base K-bar calculations, as not making adjustments to account for retirements would tend to over-state the level of rate base. Regarding retirements, Mr. Chaudhary, on behalf of EPCOR, explained that base K-bar will take account of the cumulative retirements to date, but given that the base K-bar is escalated by I-X each year, the K-bar mechanism will not take into consideration any further adjustments related to retirements. Fortis and the ATCO utilities indicated the use of a three-year or five-year average of historical retirements would be a good starting point to determine the level of retirements that should be used in the accounting test to set base K-bar; however, they also noted that a review of historical anomalies as well as any known and measurable forecast changes going forward would be necessary.[299] The Commission considers that a projected level of retirements must be included in the 2018 base K-bar calculations, and agrees that a historical average will result in a reasonable level of retirements to be used in the accounting test for each project group. Consistent with the time period used in the average of actual capital additions, the Commission approves the use of a four-year historical average of retirements from 2013 to 2016 in calculating the base K-bar amount in 2018. Similar to the findings in Section 4.2, the distribution utilities may also identify any anomalies for consideration in the rebasing application, and the Commission will consider if any adjustments to the actual retirements to be averaged are warranted.

253. Regarding the amount of depreciation expense included in the base K-bar calculation, Mr. Baraniecki, on behalf of EPCOR, explained that there will be a fixed depreciation amount incrementally added each year to account for the capital additions made in each year. Fortis indicated that the distribution utilities will be filing updated depreciation studies and that a historical average "would not be an appropriate approach for deriving the forecast of

[299] Transcript, Volume 15, page 3108, lines 5-20 (Mr. Chaudhry); Transcript, Volume 9, page 1813, line 23 to page 1814, line 22 (Ms. Sullivan); Exhibit 20414-X0624, Fortis argument, paragraph 132; Exhibit 20414-X0565, undertaking response by Mr. Grattan to Ms. Sabo at Transcript, Volume 7, page 1425, line 25 to page 1426, line 10, response to bullet 3.

depreciation." The ATCO utilities also indicated that using a historical average for depreciation would not produce a reasonable approximation of the depreciation expense associated with incremental capital funding.[300] The Commission agrees that the depreciation rates approved following the application for an updated depreciation study should be used in the base K-bar calculation. As noted in Section 4.3, the depreciation studies will be filed in 2018 and, if warranted, going-in rates will be adjusted accordingly. At the start of the next generation PBR plans, the distribution utilities will incorporate the same depreciation assumptions used during the current generation PBR plans. In addition to the going-in rates adjustment that may result if updated depreciation studies are approved, the distribution utilities will be required to submit a base K-bar adjustment to update the interim base K-bar using the updated going-in rates and the updated depreciation rates. The interim base K-bar adjustments required for approved trued-up 2016 capital tracker additions and for the depreciation and going-in rates update should be included as a part of a going-in rates true-up application. The going-in rates true-up application will result in a final base K-bar amount to be effective as of January 1, 2018, with a true-up between the interim base K-bar amount and the final base K-bar amount to be reconciled on a prospective basis in the next annual PBR rate adjustment filing. This finding on adjusting K-bar to reflect updated depreciation studies also applies to Type 1 capital trackers.

254. To summarize, the calculation of interim base K-bar will involve the following steps:

Step 1: Calculate the revenue requirement that is recovered in the base rates under the I-X mechanism for Type 2 K-bar projects or programs for 2018.

(i) Calculate the amount of revenue requirement by program or project recovered in base rates under the I-X mechanism for 2018 using going-in capital-related revenue requirement by program or project, using the method for calculating recovered capital-related revenue requirement from the capital tracker accounting test approved in the current generation PBR plans. There will, however, no longer be a materiality threshold in the accounting test, and the accounting test must be applied to all Type 2 projects or programs, not just those with positive accounting test results.

Step 2: Calculate the projected revenue requirement for Type 2 K-bar projects or programs for 2018.

(i) Distribution utilities on the 2013-2017 PBR plans will determine the capital additions for each K-bar project for each of 2013 to 2016, and ENMAX will determine the capital additions for each K-bar project for 2015 and 2016. K-bar projects include all capital projects or programs that have historical rate base associated with them at the time of the rebasing applications. For non-capital tracker programs from the current generation PBR plans, use the actual capital additions as determined to be prudent in the rebasing application, and for capital tracker projects or programs from the current generation PBR plans, use the actual capital additions approved in the capital tracker decisions. As 2016 actual capital tracker additions will not have received Commission approval at the time of the

300 Transcript, Volume 15, page 3109, lines 7-12 (Mr. Baraniecki); Transcript, Volume 9, page 1813, lines 6-13 (Ms. Sullivan); Exhibit 20414-X0624, Fortis argument, paragraph 132; Exhibit 20414-X0565, undertaking response by Mr. Grattan to Ms. Sabo at Transcript, Volume 7, page 1425, line 25 to page 1426, line 10, response to bullet 2.

rebasing application, use the 2016 applied-for actual costs from the 2016 capital tracker true-up application. The 2016 actual costs will be trued up to the amounts approved in the 2016 capital tracker true-up decisions at a later date. ENMAX will not have Commission approval for any of its capital tracker actuals. As such, ENMAX will use the applied-for actuals from its recent capital tracker true-up application for both 2015 and 2016. These amounts will be trued up at a later date.

(ii) Inflate the capital additions to 2017 dollars using the I-X methodology with the approved I factor for each year and the approved X factor for the 2013-2017 PBR plans, which is equal to 1.16. As ENMAX was not on the 2013-2017 PBR plans, it will use the X factor approved for ENMAX's 2015-2017 PBR plan, which is equal to 0.3, as noted in Section 5.5.

(iii) Calculate the average K-bar capital additions, by project, in 2017 dollars for the 2013 to 2016 period, or the 2015 to 2016 period for ENMAX.

(iv) Inflate the average K-bar capital additions by project to 2018 dollars using the I-X methodology with the approved I factor for 2018 and the X factor for the next generation PBR plans.

(v) Calculate the amount of K-bar capital cost incurred for 2018, by program or project, based on the 2018 capital additions from Step 2(iv) and the 2017 mid-year rate base using the method for calculating incurred capital costs from the capital tracker accounting test approved in Decision 2013-435. Distribution utilities should use a four-year average of inflation-adjusted retirements from 2013 to 2016 as an assumption in the accounting test.

Step 3: Calculate the base K-bar.

(i) Calculate the difference between the 2018 K-bar capital-related revenue requirement required on a projected basis by program or project (from Step 2) and the 2018 K-bar capital-related revenue requirement recovered in the base rates by program or project (from Step 1). The result is the capital funding shortfall or surplus amount for each program or project for 2018.

(ii) Sum the capital funding shortfall and surplus amounts, including both negative accounting test results and positive accounting test results without any materiality considerations, for all Type 2 projects and programs from Step 3(i) to get the total interim base K-bar for 2018.

255. Once the interim base K-bar amount is determined, it will be used as the amount of incremental capital funding for Type 2 programs in 2018, and also escalated in the annual PBR rate adjustment filings to determine the amount of incremental capital funding for the years 2019 through 2022. EPCOR and Fortis have each proposed a different formula for the escalation of base K-bar. Using EPCOR's formula, each subsequent year would have a K-bar amount equal to the 2018 base K-bar amount adjusted by I-X for the number of years necessary, added to total the K-bar amount from the previous year without an I-X adjustment to the previous year amount. Using Fortis' formula, each subsequent year would have a K-bar amount equal to the 2018 base K-bar amount adjusted by I-X for the number of years necessary, added to the total K-bar

amount from the previous year adjusted by I-X.[301] The Commission considers that when the previous year's K-bar amount is carried forward, it should not be adjusted by I-X because that prior year amount supports additions in prior years that have already been made and should not need to increase through time because those prior year amounts only depreciate over time. Therefore, the Commission approves EPCOR's calculation methodology wherein the 2018 K-bar amount is equal to base K-bar, and each year after 2018 would have a K-bar amount equal to the 2018 base K-bar amount adjusted by I-X, added to the total K-bar amount from the previous year. An example of this calculation can be found in EPCOR's Schedule 4.[302] The I factor to be applied each year will be consistent with the I factor calculated in the annual PBR rate adjustment filings. The formula to calculate the K-bar amount in 2019 through 2022 is as follows:

$$\text{K-bar}_t = \text{K-bar}_{t-1} + \text{base K-bar} \times (1 + (I_t - X)) * (1 + (I_{t-1} - X))\ldots$$

K-bar_t = K-bar factor for current year
K-bar_{t-1} = K-bar from the previous year
Base K-bar = 2018 base K-bar
I_t = inflation factor for current year
I_{t-1} = inflation factor from the previous year
X = productivity factor
$(1 + (I_{t-1} - X)) \ldots = (1 + (I_t - X))$ multipliers for all previous years

256. Fortis proposed that the K-bar amounts not be trued up annually for actual debt costs or the approved Q Factor, but that the formula would incorporate the I factor approved in the annual PBR rate adjustment filings.[303] The Commission considers that trueing up debt in the K-bar amount is inconsistent with the fact that K-bar is not subject to a true-up on capital additions and would result in an unnecessary increase to the regulatory burden. Further, the Commission considers that the I factor picks up changes in debt rate and that the I factor will be calculated each year in the annual PBR rate adjustment filings. The Commission finds that parties should use the I factor calculated in the annual PBR rate adjustment filings as a part of their annual K-bar calculation.

6.5 Service quality and asset monitoring

257. The first principle of PBR states 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. In Decision 2012-237, the Commission recognized that the creation of greater efficiency incentives through adoption of a PBR plan also creates concerns that cost reductions might lead to reductions in quality of service. The Commission found that continuing to administer Rule 002, with the addition of new metrics and the establishment of defined targets for those metrics, would satisfactorily address the requirement for service quality measurement and reporting under PBR. Accordingly, on September 13, 2012, the Commission initiated a rule consultation process with industry stakeholders and subsequently revised Rule 002, effective

[301] Exhibit 20414-X0073, Fortis PBR plan proposal, paragraph 107; Exhibit 20414-X0575, undertaking response by Ms. Sullivan to Ms. Sabo at Transcript, Volume 9, page 1805, lines 16-20; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 135-138; Exhibit 20414-X0078, EPCOR, Schedule 4.
[302] Exhibit 20414-X0078, EPCOR, Schedule 4.
[303] Exhibit 20414-X0073, Fortis PBR plan proposal, paragraph 108.

January 1, 2013, to include the addition of new metrics and the establishment of service standards.[304]

258. In Decision 2012-237, the Commission also determined that some level of asset monitoring would be required to provide increased visibility into the asset management practices of the distribution utilities and insight into the condition of the distribution utilities' assets.[305] A consultation with stakeholders on asset management reporting was launched on February 15, 2013,[306] with AUC staff meeting with the distribution utilities individually to discuss their existing asset management programs and with consumer groups to discuss their views on asset management reporting. AUC staff proposed a reporting straw model based on the discussions with stakeholders. The proposed straw model was discussed with the stakeholder group in early 2016. The outcome of the consultation process was a commitment by the distribution utilities to provide with their 2016 Rule 002 annual report filing a description of their distribution systems, their asset management programs and how the success of their asset management programs is measured.[307]

259. In response to a Commission IR in this proceeding about the potential for service quality deterioration under the various proposed capital mechanisms, most of the distribution utilities responded that they have a statutory obligation to provide safe and reliable service regardless of any incremental capital funding mechanism. Parties also indicated that the stronger service quality metrics and standards, currently reported under Rule 002,[308] provides the incentive to maintain service quality. Some distribution utilities also responded that the information submitted in the Rule 002 reports and future asset management reporting would be sufficient, and that no further changes are required to the Commission's determinations from Decision 2012-237 related to service quality and asset monitoring.[309]

260. The Commission considers that sound management of the distribution utilities' physical assets is critical to the continued provision of safe and reliable service during the next generation PBR term and beyond. The Commission considers that Rule 002, with its associated performance metrics reporting, along with asset monitoring reporting, will provide visibility into the service quality and asset management activities of the distribution utilities. These tools also will support the long-term planning and replacement activities of the distribution utilities to maintain service quality while following sound asset management practices. In accordance with the initiative set out in Decision 2012-237, the Commission will continue with its stakeholder consultation regarding further refinements to asset management reporting in 2017.

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304 Decision 2012-237, paragraphs 864 and 882; Bulletin 2012-24, AUC Rule 002: Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors, December 31, 2012.

305 Decision 2012-237, paragraphs 943-945.

306 Bulletin 2013-07, Stakeholder consultation on asset monitoring for owners of electric distribution systems and for gas distributors, February 15, 2013.

307 http://www.auc.ab.ca/rule-development/service-quality-and-reliability/Pages/default.aspx

308 Rule 002 reports are currently filed through the eFiling System. Rule 002 reports can also be found at http://www.auc.ab.ca/utility-sector/reports/Pages/ServiceQualityandReliabilityPlans.aspx

309 Exhibit 20414-X0453, PARTIES(FAI)-AUC-2016JUN03-016; Exhibit 20414-X0454, PARTIES(ATCO)-AUC-2016JUN3-016; Exhibit 20414-X0455, Parties(ENMAX)-AUC-2016JUN03-016; Exhibit 20414-X0458, PARTIES(AUI)-AUC-2016JUN03-016.

7 Calculation of returns for reopener purposes

261. A reopener provision is commonly included in PBR plans, including the current generation PBR plans, to provide a mechanism during the term of the plan to identify, assess and potentially address design or operational problems within the plan. Reopener provisions are triggered by positive or negative financial results that were unanticipated at the commencement of the plan, material and which cannot be addressed by other features of the plan.[310]

262. In Decision 2012-237, the Commission approved an ROE-based reopener mechanism for all PBR plans and determined that an earned ROE that is 500 basis points above or below the approved ROE in a single year, or 300 basis points above or below the approved ROE for two consecutive years, is sufficient to warrant consideration of a reopening and review of a PBR plan.[311] The "base" ROE against which to calculate the +/-300 or +/-500 basis point reopener thresholds for that year is the allowed ROE for a given year determined by the Commission in a generic cost of capital proceeding.[312] The actual ROE of the distribution utilities to be used to determine whether a reopener is warranted will be the ROE reported in the distribution utilities' annual Rule 005 filings.[313] [314]

263. The Commission also highlighted that a reopening of the PBR plans will not be automatic. As with any other matter before the Commission, a reopening of a PBR plan may be initiated on the Commission's own motion or on application of an interested party. The onus is on the applicant to demonstrate that a reopening is warranted.[315] The Commission further noted:

> … In order to ensure fairness to all parties, parties are directed to notify the Commission of all events that they consider signal the need for a re-opener as soon as possible after they have been identified. The Commission also directs that the financial impact of any such event be captured in a separate account pending a ruling from the Commission. Any proposed financial impact is to be measured from the time the event occurred. The disposition of the balance in that account (positive or negative) would follow the Commission's ruling.[316] [footnotes removed]

264. On February 2, 2016, the Commission issued Bulletin 2016-03,[317] in which it included, among other matters, a clarification regarding the restatement of Rule 005 results and, specifically, ROEs, as a result of adjustments to placeholder values for the distribution utilities under PBR plans. The Commission indicated that because Decision 2012-237 did not direct any specific changes to the way that ROE is to be calculated in Rule 005 filings, the distribution utilities should generally only make adjustments to the ROE that would typically have been required prior to the onset of PBR, subject to other clarifications in the bulletin.[318] The Commission emphasized that guidance was specific to distribution utilities under PBR plans

310 Decision 2012-237, paragraphs 723-724 and 727.
311 Decision 2012-237, paragraph 737.
312 Decision 2012-237, paragraph 738.
313 Decision 2012-237, paragraph 739.
314 Rule 005: *Annual Reporting Requirements of Financial and Operational Results* are annual reports filed by the distribution utilities in May of the year which follows the reporting year. The reporting year is defined as January 1 to December 31 of the year preceding the May filing deadline.
315 Decision 2012-237, paragraph 757.
316 Decision 2012-237, paragraph 758.
317 Bulletin 2016-03, Clarification of Rule 005 financial reporting requirements, February 2, 2016.
318 Bulletin 2016-03, sections 3 and 3.2.

established in Decision 2012-237, and may be subject to change for the next generation of PBR, based on determinations in this proceeding.[319]

265. In its August 21, 2015 letter establishing the scope of this proceeding, the Commission indicated that changes to Rule 005 were outside the scope of this proceeding, given that the requirements of Rule 005 apply to all utilities and not just the distribution utilities registered in this proceeding.[320] However, the Commission stated it saw merit in "clarifying the reopener parameters for a next generation PBR plan" and included the issue of calculating ROE for reopener purposes in the final issues list.[321]

266. The Commission heard evidence on whether to continue to use ROE as reported in Rule 005 filings for reopener purposes in the next generation PBR plans or to use an ROE reflective of final approved adjustment amounts for the reporting year arising from the Commission's subsequent decisions and rules. To the extent these final approved amounts are not available at the time of the Rule 005 filings, the latter approach would require a restatement of an ROE result reported in Rule 005 for that year.

267. Parties' views on this issue were divided among two main approaches, with some variations. The ATCO utilities and Fortis proposed to continue to use the ROE from Rule 005 reports, in accordance with the method approved in Decision 2012-237 and clarified in Bulletin 2016-03.[322] AltaGas, Calgary, the CCA, EPCOR and the UCA supported some form of a restatement of actual ROEs reported in Rule 005 or a reconciliation between Rule 005 returns and the changes after Rule 005 filings have been made, to adjust for the changes arising from subsequent Commission decisions and rules.[323] In its PBR plan proposal, ENMAX supported using the returns reported in Rule 005 without any adjustments.[324] However, in response to a Commission IR, ENMAX indicated it would not object to normalizing the Rule 005 ROE for reopener purposes, to reflect material revenue effects resulting from the Commission's rulings and decisions.[325]

268. The objective of the reopener provision has always been to ensure, to the extent possible, that a utility's performance under PBR is measured accurately, and on a timely and consistent basis. Accurate performance information is essential in order to identify, assess and consider timely adjustments to the plan prior to the end of the term.

269. In paragraph 758 of Decision 2012-237, reproduced earlier in this section, the Commission directed parties "to notify the Commission of all events that they consider signal the

319 Bulletin 2016-03, Section 4.
320 Exhibit 20414-X0026, AUC letter – Final issues list, August 21, 2015, paragraph 47.
321 Exhibit 20414-X0026, AUC letter – Final issues list, August 21, 2015, paragraph 48 and attachment, PDF page 12.
322 Decision 2012-237, paragraphs 737-739; Exhibit 20414-X0070, ATCO PBR plan proposal, paragraphs 81-85; 20414-X0073, Fortis PBR plan proposal, paragraph 115.
323 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 100-104; Exhibit 20414-X0616, AltaGas argument, PDF pages 34-35; Exhibit 20414-X0071, Calgary PBR plan proposal, PDF pages 64-69; Exhibit 20414-X0625, Calgary argument, paragraphs 180-186; Exhibit 20414-X0630, CCA revised argument, paragraph 129; Exhibit 20414-X0422, CCA rebuttal evidence of Mr. Thygesen, paragraphs 70-73; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 160-167; Exhibit 20414-X0256, EDTI-AUC-2016APR15-031; Transcript, Volume 13, page 2566, lines 12-20 (Mr. Baraniecki); Exhibit 20414-X0066, UCA evidence of Mr. Bell, PDF pages 31-33; Exhibit 20414-X0632, UCA reply argument, paragraph 84.
324 Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 57.
325 Exhibit 20414-X0157, EPC-AUC-2016APR15-017(d).

need for a re-opener as soon as possible after they have been identified." The Commission continues to hold this view. The ROE from Rule 005 reports may serve as an initial indicator that a reopener threshold has been met.

270. In considering whether a reopener may be required based on the ROE from a Rule 005 report, a distribution utility may be asked for ROE adjustments to account for any outstanding true-up amounts and unusual events that may have affected a distribution utility's earnings. ENMAX referred to this process as an ROE "normalization" that would ensure the approved revenues and costs for the reporting year are aligned.

271. Parties to this proceeding pointed out that differences in timing as to when certain revenues and costs (for example, approved capital additions to rate base) are recognized in distribution utilities' financial statements, and when these items are collected from customers, affect the ROE calculation. As a result, depending on the assumptions used, an ROE reported in Rule 005 may not be reflective of the most accurate matching of approved revenues and costs for the reporting year. In the 2013-2017 PBR term, capital tracker revenues were the most prominent source of such mismatching because the amounts were material and because the final approved amounts were not known until a year or two after related costs were reflected in a Rule 005 report.

272. The Commission agrees with the submissions of those parties who indicated that restating the Rule 005 ROE to reflect the final approved amounts from subsequent Commission decisions and rules would ensure that approved revenues for a given year are matched better to actual costs for that year, resulting in a more accurate measurement of the distribution utilities' performances under PBR.[326] Additionally, the restated ROEs, reflective of final approved amounts and actual costs, rather than of individual distribution utility assumptions based on the information available at the time, will result in greater comparability of achieved returns among distribution utilities operating under PBR. For these reasons, the Commission will require the distribution utilities to restate the ROEs reported in their Rule 005 reports.

273. Those parties supporting the use of restated ROEs for reopener purposes differed in their views on what qualifies for a restatement and how often to restate. Regarding the frequency of restatements, the Commission considers that multiple adjustments throughout the year as suggested by Calgary,[327] are unnecessary. The Commission finds reasonable the proposal by AltaGas, Mr. Thygesen, on behalf of the CCA, ENMAX and EPCOR to restate ROE annually, as part of the annual PBR rate adjustment filings.[328] The Commission considers that a continued annual adjustment of the ROE is warranted where new final data becomes available. For instance, the 2018 ROE reported in the Rule 005 filing made in May 2019, could be restated in the 2020 annual PBR rate adjustment filing in September 2019 and updated again in the 2021 annual PBR rate adjustment filing, and so on, as more final data pertaining to 2018 becomes available.

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326 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 98-99; Exhibit 20414-X0625, Calgary argument, paragraph 183; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 161 and 165; Transcript, Volume 13, page 2566, lines 12-20 (Mr. Baraniecki).

327 Exhibit 20414-X0625, Calgary argument, paragraph 184.

328 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 101-103; Exhibit 20414-X0422, CCA rebuttal evidence of Mr. Thygesen, paragraph 71; Exhibit 20414-X0554, undertaking response by Mr. Hildebrandt to Ms. Wall at Transcript, Volume 8, page 1570, lines 16-19; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 164.

274. The Commission is of the view that the distribution utilities do not need to restate the entirety of the Rule 005 schedules from a given year. The Commission finds reasonable the proposals of AltaGas and EPCOR, supported by Mr. Thygesen, on behalf of the CCA, that restated ROE calculations can be provided annually in a separate schedule filed with the annual PBR rate adjustment filings.[329] Accordingly, the Commission directs each of the distribution utilities to include in each annual PBR rate adjustment filing commencing in 2019, an ROE adjustment schedule for each completed year during the next generation PBR term following the format of the Reconciliation of Financial & Utility Returns schedule, as required by paragraph 861 of Decision 2012-237, currently filed as part of the annual PBR rate adjustment filings. The new schedule should start with the ROE number from the Rule 005 report for a given year, and then list line items capturing the effects of any regulatory decisions not included in the original Rule 005 report that affect the distribution utility's revenues and costs, including the amount of equity, to arrive at the restated ROE number for that year. As part of this schedule, the distribution utilities are directed to provide a detailed description of each adjustment, with references to Commission decisions or rules approving the final amounts from which the adjustment arises.

275. Since the regulatory burden (i.e., the required explanations and supporting schedules) associated with this approach is commensurate with the number and magnitude of adjustments to an ROE number, the Commission will not adopt the materiality criteria for ROE restatements, as proposed by some parties.[330] The distribution utilities are directed to restate an ROE for a given year based on all of the available final approved amounts pertaining to that year. The Commission considers that in this case too, an ROE normalization process may be warranted; that is, in considering whether a reopener may be required, a distribution utility may be asked for ROE adjustments to account for any outstanding true-up amounts and unusual events that may have affected a distribution utility's earnings.

276. In order to achieve a continuity of restated ROE numbers, in all subsequent ROE adjustment schedules for a given year, the distribution utilities are directed to carry forward the line items and the resulting subtotals and the ROE result from the previous ROE adjustment schedule for that year. The newly identified line items, their subtotals and the new ROE result should then be presented below the previously restated ROE number. This way, in each subsequent ROE adjustment schedule, parties will have available the ROE from Rule 005 reports, each of the previously restated ROE results as well as the latest restated ROE number.

277. The latest information available, be it the initial Rule 005 filing or a subsequent ROE restatement filed as part of the annual PBR rate adjustment filing, can serve as a basis for a reopener application. To clarify, a Rule 005 ROE for a given year may serve as a reopener trigger only prior to the filing of a restated ROE for that year. When several restated ROEs for a given year are available, the most recent restatement from the latest annual PBR rate adjustment filing is to be used.

329 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 101-103; Exhibit 20414-X0639, AltaGas reply argument, paragraphs 75-76; Exhibit 20414-X0422, CCA rebuttal evidence of Mr. Thygesen, paragraph 71; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 166.

330 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 104; Transcript, Volume 10, page 2079, lines 17-19 (Mr. Thygesen); Transcript, Volume 14, page 3000, line 9 to page 3003, line 7 (Mr. Baraniecki, Mr. Zurek, Mr. Chaudhary); Exhibit 20414-X0582, undertaking response by Mr. Chaudhary to Ms. Wall at Transcript, Volume 14, page 3003, lines 17-22.

278. Finally, AltaGas, the ATCO utilities, Calgary and Fortis proposed that the calculation of the ROE for assessing reopeners should not include amounts provided to the distribution utilities through the ECM approved in the 2013-2017 PBR plans, that will be collected in 2018 and 2019, in accordance with the approvals in Section 4.4 of this decision.[331] Although the distribution utilities will include the dollar amounts associated with the ECM approved in the 2013-2017 PBR plans in their financial reports for 2018 and 2019, the Commission agrees that the calculation of the ROE for assessing reopeners should not include amounts provided to the distribution utilities by the ECM approved in the 2013-2017 PBR plans, because these amounts arise from the operation of the previous generation of PBR and would not be indicative of potential design or operational problems under the terms of the next generation PBR plans. Accordingly, these ECM amounts should not be factored into the calculation of the reports filed to consider the potential need for a reopener.

279. Reopener considerations, other than the calculation of ROE based on Rule 005 filings or final returns, are outside the scope of this proceeding. Accordingly, with the exception of the Commission's determinations above on the ROE to be used for the purpose of determining if the reopener thresholds have been met, no other changes will be made to the reopener provisions set out in Decision 2012-237.

280. Specifically, the Commission will continue to employ the +/-500 basis point threshold in a single year and the +/-300 basis point thresholds for two consecutive years as warranting consideration of a reopening and review of a PBR plan.[332] The UCA's proposal for a +/-800 basis points threshold to be applied on a cumulative ROE basis over a PBR term is outside the scope of this proceeding.[333] AltaGas' proposal to use a blended generic ROE calculated by using a weighted average of the various PBR formula components is similarly outside the scope of this proceeding.[334] The Commission will utilize an allowed ROE for a given year, as determined by the Commission in a generic cost of capital proceeding, as the "base" ROE against which to calculate the +/-300 or +/-500 basis point reopener thresholds for that year.[335]

8 Other matters

281. In their submissions, in addition to addressing the four issues in scope for this proceeding, parties made proposals or filed evidence relating to other PBR-related matters. Some of these issues, for example, re-examining the I factor,[336] or shorting the term of the next generation PBR plan,[337] have been expressly excluded from consideration as a result of the scoping process that resulted in the Commission's final issues list. Other issues would require a specialized proceeding. For example, the UCA's and ENMAX's rate design proposals to alter

331 Exhibit 20414-X0616, AltaGas argument, paragraph 100; Transcript, Volume 5, page 847, lines 10-15 (Mr. Stock); Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 86; Exhibit 20414-X0636, Calgary reply argument, paragraph 184; Transcript, Volume 16, page 3314, lines 17-25 (Mr. Johnson); Exhibit 20414-X0073, Fortis PBR plan proposal, paragraph 46.
332 Decision 2012-237, paragraph 737.
333 Exhibit 20414-X0451, PARTIES(UCA)-AUC-2016JUN03-018(d).
334 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 108-109.
335 Decision 2012-237, paragraph 738.
336 Exhibit 20414-X0616, AltaGas argument, paragraphs 8 and 24-25; Exhibit 20414-X0619, ENMAX argument, paragraph 94.
337 Exhibit 20414-X0622, ATCO argument, paragraphs 6 and 31; Exhibit 20414-X0632, UCA reply argument, paragraphs 27-28.

the proportion of distribution fixed and variable charges included in rates, are Phase II matters best addressed in a Phase II utility specific, or generic, proceeding.

282. AltaGas proposed to re-evaluate the current method for calculating billing determinants, approved in Decision 2012-237, to take into account the potential effect of lag from use of rolling averages, particularly during periods of economic volatility.[338] The CCA proposed an enhancement to the distribution utilities' reporting requirements to make them more tailored to the PBR framework, such as, for example, to show separately costs subject to I-X and costs subject to other factors, although it appears that this proposal was made in a context of rebasing.[339]

283. Although these proposals are beyond the scope of the present proceeding, the Commission is prepared to entertain proposals of this type, after the next generation rebasing process has been completed and 2018 PBR rates have been set on an interim basis. Any such proposal must be able to demonstrate that the proposal will result in improved efficiencies without affecting the incentive properties of next generation PBR plans or would address issues of improved rate design or cost allocation among rate classes.

9 Conclusion

284. In this decision, the Commission has sought to build on its experience with the 2013 to 2017 PBR plans as well as its experience with the 2007 to 2013 ENMAX FBR plan and to respond to the requests of the parties to this proceeding to develop a next generation PBR framework built on the five PBR principles adopted by the Commission in Bulletin 2010-20.[340] Those principles are:[341]

> **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3.** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

285. The Commission's approach to building a PBR regime based on the five PBR principles has been to consider the inter-relationships among all of the PBR elements, both those being considered in this proceeding and those that will remain from the 2013 to 2017 PBR plans, rather

338 Exhibit 20414-X0616, AltaGas argument, paragraphs 8 and 28-29; Exhibit 20414-X0639, AltaGas reply argument, paragraphs 30-31.
339 Exhibit 20414-X0630, CCA revised argument, paragraphs 61, 105 and 109.
340 Bulletin 2010-20, Regulated Rate Initiative – PBR Principles, July 15, 2010.
341 Decision 2012-237, paragraph 28.

than only considering each element discretely. For example, in this proceeding the Commission's focus in setting the 2017 going-in rates for each distribution utility will be on using its judgement to estimate the costs that each distribution utility operating under the incentives of the PBR mechanism, unencumbered by incentives inconsistent with the PBR incentives, would have incurred in 2017 rather than being based on the distribution utilities' cost forecasts. The Commission has turned its attention to the going-in rates in recognition of the significant effects those rates can have on the distribution utilities' decision making and the outcomes of a PBR plan. Without going-in rates that seek to emulate competitive market cost structures achieved under the PBR incentives, other objectives of PBR can be compromised.

286. The Commission has also responded to concerns that the capital tracker mechanism adopted in the 2013-2017 PBR plans had the unintended effect of placing a considerable amount of capital outside of the incentive-enhancing I-X mechanism. In effect, capital trackers had to be administered in a manner similar to traditional COS regulation which parties agree has inferior incentive properties. Accordingly, the Commission has adopted a capital funding model that provides the necessary incremental capital funding for the distribution utilities while enhancing significantly the incentives to plan, design and construct capital assets efficiently. The Commission's approach to incremental capital funding is expected to reduce the regulatory burden over time, is easier to understand than the current capital tracker model, expands PBR incentives to the vast majority of overall costs and also allows the PBR plan to recognize the unique circumstances of each distribution utility and how the Alberta economy may affect each distribution utility.

287. The Commission is mindful that the distribution utilities raised concerns about a reasonable opportunity to earn their allowed rate of return and did so often in discrete discussions about each of the individual elements of PBR being considered in this proceeding. The Commission emphasizes that one cannot assess the opportunity to earn a reasonable rate of return based on examining each individual PBR parameter in isolation. Nor can the distribution utilities assume that any decision of the Commission to provide less assurance of cost recovery for one discrete element than they may have requested amounts to a denial of a reasonable opportunity to earn the allowed rate of return over the next generation PBR plans. The reasonable opportunity to earn their allowed rate of return is premised not only on the Commission's duty to turn its mind to regulated revenue streams for the distribution utilities, it also includes a duty of the distribution utilities to conduct their business in a way that meets their obligations and to do so in a way that contributes to their own success in earning their allowed rate of return or better.

288. The Commission has addressed the distribution utilities' reasonable opportunity to earn their allowed rates of return through the going-in rates and the incremental capital funding within the context of the overall next generation PBR plan, including the I-X formula. The X factor, combined with the I factor, is designed to create incentives similar to those in competitive markets. The Commission will apply the I-X formula to the 2017 notional going-in rates for each distribution utility as determined by the Commission. The Commission will then apply the incremental capital funding to recognize the unique circumstances of each distribution utility, and take into account all of the other elements of the PBR plan in place to mitigate the effects of unexpected cost increases or decreases. Based on its experience, administering the capital trackers in the 2013-2017 PBR plans and observing the evolution of operating and maintenance expenses of the distribution utilities during that time, having regard to the evidence filed in this proceeding and the elements of the PBR plans that it has approved in this decision, and applying

its expertise and judgement in carrying out its mandate to set just and reasonable rates, the Commission is satisfied that the distribution utilities will have a reasonable opportunity to earn their allowed rates of return over the next generation PBR plans.

10 Order

289. It is hereby ordered that:

(1) Each of AltaGas Utilities Inc., ATCO Electric Ltd. (distribution), ATCO Gas and Pipelines Ltd. (distribution), ENMAX Power Corporation (distribution), EPCOR Distribution & Transmission Inc. (distribution) and FortisAlberta Inc. shall file a compliance filing by way of a rebasing application in accordance with the directions set out in this decision by March 31, 2017. The rebasing applications by each distribution utility shall provide the proposed components of a 2017 notional revenue requirements with supporting documentation. The rebasing applications may include placeholder values and shall be updated with supplemental filings as information on actual or approved numbers becomes available. The updates are directed to be filed as follows:

- On or before July 1, 2017, each of the distribution utilities shall update its rebasing application by filing the audited 2016 actual financial results from its Rule 005 reports as well as the applied-for 2016 actual capital tracker amounts and, if applicable, final approved 2015 actual capital tracker amounts.
- On or before September 10, 2017, each of the distribution utilities will update its rebasing application by updating its 2017 notional revenue requirement and requesting approval on an interim basis of 2018 PBR rates calculated based on the application of the I-X index and any K factor, K-bar factor, Y factor, and Z factor amounts to the going-in rates calculated in the manner directed in Section 4 of this decision.

Dated on December 16, 2016.

Alberta Utilities Commission

(original signed by)

Willie Grieve, QC
Chair

(original signed by)

Neil Jamieson
Commission Member

(original signed by)

Henry van Egteren
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
AltaGas Utilities Inc.
ATCO Gas, a division of ATCO Gas and Pipelines Ltd. (ATCO Gas)   Bennett Jones LLP
ATCO Electric Ltd.
ENMAX Power Corporation
EPCOR Distribution & Transmission Inc.   Fasken Martineau Dumoulin LLP
FortisAlberta Inc.
Devon Canada
AltaLink Management Ltd.
The City of Calgary   McLennan Ross Barristers & Solicitors
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA)   Brownlee LLP

Alberta Utilities Commission
 	
Commission panel
    W. Grieve, QC, Chair
    N. Jamieson, Commission Member
    H. van Egteren, Commission Member
 	
Commission staff
    B. McNulty (Associate General Counsel)
    C. Wall (Commission counsel)
    A. Sabo (Commission counsel)
    O. Vasetsky
    C. Runge
    B. Miller
    J. Bezuidenhout
    A. Corsi
    E. Deryabina
    D. Ryan
    S. Levin

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) **Name of counsel or representative**	**Witnesses**
AltaGas Utilities Inc., the ATCO Utilities, ENMAX Power Corporation and FortisAlberta Inc. D. Wood	Brattle panel: P. Carpenter T. Brown
AltaGas Utilities Inc. N. McKenzie	G. Johnston M. Stock R. Retnanandan D. McKenzie
ATCO Gas and ATCO Electric Ltd. L. Smith, QC K. Illsey	M. Bayley B. Howell V. Berger J. Grattan
ENMAX Power Corporation D. Wood	J. Mosley K. Hildebrandt
FortisAlberta Inc. T. Dalgleish, QC B. Ho	J. Sullivan C. Eck
EPCOR Transmission & Distribution Inc. J. Liteplo J. Hulecki	J. Baraniecki S. Chaudhary G. Zurek M. Meitzen D. Weisman
Office of the Utilities Consumer Advocate (UCA) T. Marriott, QC A. Preda	D. Simpson R. Bell K. Pavlovic
The City of Calgary D. Evanchuk	H. Johnson G. Matwichuk
Consumers’ Coalition of Alberta (CCA) J. Wachowich, QC S. Gibbons	M. Lowry J. Thygesen

Alberta Utilities Commission

Commission panel

W. Grieve, QC, Chair
N. Jamieson, Commission Member
H. van Egteren, Commission Member

Commission staff

C. Wall (Commission counsel)
A. Sabo (Commission counsel)
O. Vasetsky
C. Runge
B. Miller
D. Ryan
S. Levin

Appendix 3 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. Having considered the evidence and argument of the parties and after applying its judgement in light of the objectives and purposes of rebasing as described earlier in this section, the Commission does not consider it necessary or desirable to employ a 2018 forecast COS year in order to set going-in rates. Rather, the Commission has determined that it will set going-in rates on the basis of a notional 2017 revenue requirement using actual costs experienced during the current generation PBR term for each distribution utility with any necessary adjustments to reflect individual distribution utility anomalies. The Commission's focus in setting the 2017 going-in rates for each distribution utility will be on using its judgement to estimate the costs that each distribution utility operating under the incentives of the PBR mechanism, unencumbered by incentives inconsistent with the PBR incentives, would have incurred in 2017. It agrees with those parties who submitted using actual pre-2017 costs to develop a notional 2017 revenue requirement, adjusted as required for anomalies, best reflects expected revenues and costs without the distorting influence of the incentives which arise during the last year of a PBR term. The Commission directs each distribution utility to file on or before March 31, 2017, an application to determine a notional 2017 revenue requirement to be used to determine the going-in rates used in setting 2018 PBR rates. The Commission will establish a proceeding for the March 31, 2017 compliance filings. The distribution utilities are directed to file their respective applications under the proceeding number advised by the Commission at a later date. The period of data and mechanisms to be used are specified below. .... Paragraph 46

2. To accommodate the March 31, 2017 filing date for rebasing applications, the Commission directs the distribution utilities to use their available 2016 actual unaudited data as a placeholder for actual 2016 O&M costs and actual rate base. When audited 2016 actual data become available in the May 2017 Rule 005 filings, each distribution utility is directed to file an amendment to their rebasing application to update the 2016 actual O&M and capital data. .... Paragraph 50

3. As noted earlier in this section, there was widespread recognition among the parties that, unless streamlined, rebasing applications for six distribution utilities may result in significant regulatory burden. The Commission agrees. To aid in the assessment of their rebasing compliance applications to this decision, the Commission directs the distribution utilities to provide their Rule 005 reports for each of 2013, 2014 and 2015, and their available 2016 actual data (with a view of updating them when the 2016 Rule 005 report becomes available). The distribution utilities are also required to fill out the template that the Commission will provide by January 31, 2017, and to fully describe any deviations from the utilization of the lowest actual annual O&M expenditures in arriving at the 2017 notional revenue requirement estimate. .... Paragraph 63

4. In light of these considerations, the Commission finds reasonable EPCOR's proposal to calculate the ECM amount by applying the ECM ROE add-on to the 2017 mid-year rate base and escalating the obtained ECM dollar amount by the approved next generation

I-X value for each for 2018 and 2019, with subsequent true-up. Consistent with the overall rebasing approach set out in sections 4.1 and 4.2, the Commission directs the distribution utilities on the 2013-2017 PBR plans to calculate the interim ECM amount by applying the ECM ROE add-on to the interim 2017 notional estimated mid-year rate base and escalating the obtained interim ECM dollar amount by the approved I-X value for each of 2018 and 2019. Following the determination of a final 2017 notional estimated mid-year rate base (reflective of the final approved 2016 and 2017 K factor amounts), the ECM add-on percentage will be determined as a final dollar amount for each qualifying distribution utility, escalated by the approved I-X value for each of 2018 and 2019. .... Paragraph 84

5. During the 2013-2017 PBR plans, capital tracker true-up applications included a discussion of the variance between the approved capital tracker forecast and the actual costs, which was used as one of the tools for parties to assess the prudence of the true-up amounts. Distribution utilities will no longer have a Commission-approved forecast that was assessed for reasonableness at the time of their true-up application; however, the Commission still finds value in receiving a variance explanation from the distribution utilities. The Commission directs the distribution utilities to prepare a variance analysis comparing the internal forecast, submitted during the application for the placeholder amount, to the actual costs. The Commission will utilize this information together with other supporting documentation with respect to the prudence of the expenditures (e.g., comparing actuals to trends in prior years or engineering studies provided by intervener groups questioning the costs) in determining prudence of the true-up amounts. .... Paragraph 235

6. The Commission is of the view that the distribution utilities do not need to restate the entirety of the Rule 005 schedules from a given year. The Commission finds reasonable the proposals of AltaGas and EPCOR, supported by Mr. Thygesen, on behalf of the CCA, that restated ROE calculations can be provided annually in a separate schedule filed with the annual PBR rate adjustment filings. Accordingly, the Commission directs each of the distribution utilities to include in each annual PBR rate adjustment filing commencing in 2019, an ROE adjustment schedule for each completed year during the next generation PBR term following the format of the Reconciliation of Financial & Utility Returns schedule, as required by paragraph 861 of Decision 2012-237, currently filed as part of the annual PBR rate adjustment filings. The new schedule should start with the ROE number from the Rule 005 report for a given year, and then list line items capturing the effects of any regulatory decisions not included in the original Rule 005 report that affect the distribution utility's revenues and costs, including the amount of equity, to arrive at the restated ROE number for that year. As part of this schedule, the distribution utilities are directed to provide a detailed description of each adjustment, with references to Commission decisions or rules approving the final amounts from which the adjustment arises. .... Paragraph 274

7. Since the regulatory burden (i.e., the required explanations and supporting schedules) associated with this approach is commensurate with the number and magnitude of adjustments to an ROE number, the Commission will not adopt the materiality criteria for ROE restatements, as proposed by some parties. The distribution utilities are directed to restate an ROE for a given year based on all of the available final approved amounts pertaining to that year. The Commission considers that in this case too, an ROE normalization process may be warranted; that is, in considering whether a reopener may

Appendix 4 – AUC letter – Final issues list, August 21, 2015

(return to text)

Appendix 4 - AUC
letter - Final issues list

(consists of 12 pages)

Appendix 5 – Parameters of the 2013-2017 PBR plans that continue into and form part of the next generation PBR plans

(return to text)

The Commission has included this appendix for information purposes to summarize previous Commission PBR plan directions that remain in place for the next generation PBR term. To the extent that discrepancies exist between this appendix and previous AUC decisions, the directions from previous AUC decisions will prevail unless they have been specifically overridden elsewhere in this decision.

1. Price cap or revenue cap

The Commission will continue to employ a price cap for electric distribution utilities (ATCO Electric, ENMAX, EPCOR and Fortis) and a revenue-per-customer cap for natural gas distribution utilities (AltaGas and ATCO Gas).

Both price cap and revenue-per-customer cap plans rely on an I-X indexing mechanism that eliminates the link between revenues from the costs of service over the course of the PBR term, thus creating efficiency incentives, as illustrated by the following general formulas.

For the price cap:

$$\textbf{Rates}_t = \textbf{Rates}_{t-1} * (1 + I - X) \pm \textbf{Other Adjustments}$$

For the revenue-per-customer cap:

$$\textbf{Revenue per customer}_t = \textbf{Revenue per customer}_{t-1} * (1 + I - X) \pm \textbf{Other Adjustments}$$

2. I factor

The inflation factor, also referred to as an I factor or an input price index, is the component of a price cap or revenue cap PBR plan that reflects the expected changes in the prices of inputs that the distribution utilities use.

The Commission will continue to employ a composite I factor consisting of two indexes; one for labour and one for non-labour costs, that are published by Statistics Canada on a regular basis.

The I factor to be used in the PBR plans of the Alberta distribution utilities shall be calculated as follows:

$$I_t = 55\% * AWE_{t-1} + 45\% * CPI_{t-1},$$

where:

I_t	Inflation factor for the following year.
AWE_{t-1}	Alberta average weekly earnings (AWE) index for the previous July through June period.[342]

[342] The selection of the start and ending months for the 12-month period reflects the latest published Statistics Canada data prior to September.

CPI_{t-1} Alberta consumer price index (CPI) for the previous July through June period.[343]

The Alberta AWE series from Statistics Canada Table 281-0063, data vector V79311387, be used as the labour cost component of the I factor,[344] and Alberta CPI series from Statistics Canada Table 326-0020, data vector V41692327, be used as the non-labour cost component of the I factor. The distribution utilities in their annual PBR rate adjustment filings will use the inflation indexes for the most recent 12-month period for which data is available, as specified in the formula above. The distribution utilities will use the unrevised actual index values from the prior year's I factor filing as the basis for the next year's I factor calculations.

If a termination, substantial revision or substantial modification to the Statistics Canada data series used in the distribution utilities' I factors occurs, such changes should be brought forward to the Commission as part of the annual PBR rate adjustment filings. Any changes to the I factors arising from such data series modifications will be dealt with on a case-by-case basis.

3. Y factor

Y factor costs are costs that are flowed through to customers. For costs to be eligible for Y factor treatment, all of the following criteria must be met:

(i) The costs must be attributable to events outside management's control.

(ii) The costs must be material. They must have a significant influence on the operation of the distribution utility; otherwise the costs should be expensed or recognized as income, in the normal course of business.

(iii) The costs should not have a significant influence on the inflation factor in the PBR formulas.

(iv) The costs must be prudently incurred.

(v) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

In addition to those Y factors that meet the above criteria, the Commission will allow the distribution utilities to recover as Y factor rate adjustments, specific costs incurred at the direction of the Commission and flow-through costs that have been approved for continued flow-through treatment under the distribution utilities' PBR plans.

The following types of costs have been determined by the Commission to satisfy the Y factor criteria enumerated above:

(a) AESO flow-through items

(b) Farm transmission costs

[343] The Commission recognizes that Alberta CPI information for July may be available when the September annual PBR rate adjustment filing is made but the Commission is directing the July through June period in order to ensure the distribution utilities have enough time to prepare their filings.

[344] As per the update in the 2014 annual PBR rate adjustment decisions. See, for example, Decision 2013-462: EPCOR Distribution & Transmission Inc. 2014 Annual PBR Rate Adjustment Filing, Proceeding 2823, Application 1609912-1, December 20, 2013, paragraph 41.

(c) Accounts that are a result of Commission directions (e.g., AUC assessment fees, intervener hearing costs, UCA assessment fees, AUC tariff billing and load settlement initiatives, Commission-directed Rural Electrification Associations (REA) acquisitions, effects of regulatory decisions)

(d) Income tax impacts other than tax rate changes

(e) Municipal fees

(f) Load balancing deferral accounts

(g) Weather deferral account (ATCO Gas only)

(h) Production abandonment costs

4. ECM

An ROE ECM will be included in the distribution utilities' next generation PBR plans. The ECM will be calculated as directed by the Commission in Section 4.4 of this decision.

5. Term

The Commission considered that a five-year fixed term for the distribution utilities' PBR plans is reasonable.

6. Maximum investment levels

Maximum investment levels (MILs) and specific customer contributions will continue to be escalated by I-X throughout the PBR term.

In Decision 2012-237, the Commission made an exception to the provision above for Fortis' residential and street lighting rate classes, which will be escalated by I-X plus 10 per cent per year throughout the PBR term.[345] In its compliance filing to this decision, Fortis is directed to explain whether this exception is still warranted for its next generation PBR term.

Service fees will also continue to be escalated by I-X throughout the PBR term.

7. Service quality

The Commission will continue to rely on the legislative provisions, including the imposition of penalties, to address enforcement issues should service quality degrade. The mechanism to monitor service quality will continue to be defined by Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*.

For further discussion on service quality and asset monitoring provisions please refer to Section 6.5 of this decision.

[345] Decision 2012-237, paragraph 850.

8. Z factor

The Commission continues to consider it necessary to include the Z factor in the PBR plan to allow for an adjustment to a distribution utility's rates to account for a significant financial impact (either positive or negative) of an exogenous event outside of the control of the distribution utility and for which the distribution utility has no other reasonable opportunity to recover the costs within the PBR formula.

The Commission considers that the following criteria will apply when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

(i) The impact must be attributable to some event outside management's control.

(ii) The impact of the event must be material. It must have a significant influence on the operation of the distribution utility; otherwise the impact should be expensed or recognized as income, in the normal course of business.

(iii) The impact of the event should not have a significant influence on the inflation factor in the PBR formula.

(iv) All costs claimed as an exogenous adjustment must be prudently incurred.

(v) The impact of the event was unforeseen.

The Commission considers that all of the above criteria must be met in order for an item to qualify for a Z factor rate adjustment. The Commission considers that Z factors should be symmetrical in that they should apply to exogenous events with both additional costs that the distribution utility needs to recover and also reductions to costs that need to be refunded to customers.

The Commission establishes the threshold for use in (ii) above as the dollar value of a 40 basis point change in ROE on an after-tax basis calculated on the distribution utility's equity used to determine the final approved notional revenue requirement on which going-in rates were established (2017). This dollar amount threshold is to be escalated by I-X annually. The distribution utilities are directed to calculate and file the 2017 threshold amount along with supporting calculations on an interim basis in the compliance filing to this decision and on a final basis upon approval of the final 2017 notional revenue requirement.

Z factor rate adjustment applications are generally to be filed as part of the annual PBR rate adjustment filing. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis.

9. Earnings sharing mechanism

The Commission continues to consider that the earnings sharing mechanism is not warranted for the reasons provided in Decision 2012-237.

10. Financial reporting requirements

In its annual PBR rate adjustment filing, each distribution utility shall continue to provide:

(a) A copy of its Rule 005 filing.

(b) A schedule showing disallowed costs, excluded from a distribution utility's ROE.

(c) Attestations and certifications signed by a senior officer of the distribution utility.

Although the distribution utilities are not required to file a complete set of minimum filing requirements (MFRs) and general rate application (GRA) schedules annually, the distribution utilities must continue to maintain the ability to file a complete set of MFRs and GRA schedules with actual results for all years within the term of the PBR plans, unless otherwise directed or exempted by the Commission.

In Bulletin 2016-03,[346] the Commission clarified how some of the information is to be provided in Rule 005 reports, which applies to both distribution and transmission electric and gas utilities. Much of the guidance provided in that bulletin will continue to apply, including:

- The deemed capital structure for a distribution utility should be used instead of actual capital structure in the calculation of ROE.
- No restatements of Rule 005 reports are required when interim capital structures are replaced by final approved capital structures after the end of the reporting year.
- The guidance provided on how to determine the approved capital structure for distribution utilities whose rates are set using PBR.

However, the guidance in Bulletin 2016-03 related to restatements not being required for adjustments to placeholder values for distribution utilities under PBR plans approved in Decision 2012-237 has been replaced by the guidance in Section 7 of this decision.

11. Annual filing requirements

(i) Annual PBR rate adjustment filing

The Commission determines that the effective date for annual PBR rate changes will be January 1 each year. As such, the annual PBR rate adjustment filing is to be made by September 10 of each year.

The following items must be included in the annual PBR rate adjustment:

- Z factors approved during the previous 12 months
- K factor and K-bar factor adjustments related to approved Type 1 and Type 2 capital
- Y factor adjustment to collect Y factors that are not collected through separate riders
- billing determinants for each rate class
- backup showing the application of the formula by rate class and resulting rate schedules
- a copy of the Rule 005 filing filed in the current year as well as the ROE adjustment schedules for prior years as set out in Section 7
- any other material relevant to the establishment of current year rates

Applications related to flow-through items may be submitted throughout the year.

346 Bulletin 2016-03, Clarification of Rule 005 financial reporting requirements, February 2, 2016.

The distribution utilities will provide a revised forecast of their billing determinants annually as part of the September 10 annual PBR rate adjustment filings. Distribution utilities should utilize consistent billing determinant forecasting methodologies during the PBR term unless the Commission orders otherwise. Distribution utilities will describe the methodology they plan to use for the duration of the PBR term as part of their compliance filings to this decision. These billing determinants will generally be used to allocate K, K-bar, Y and Z factors to rate classes and to calculate the resulting rate adjustments, and will also be used in performing the annual use-per-customer adjustments for gas distribution utilities. In Decision 2012-237 the Commission stated that this billing determinant information along with the Phase II methodologies in place for each distribution utility would be the method used for allocating these factors.[347] However, in Decision 2013-072 the Commission also granted permission for distribution utilities to use a simplified approach to calculating rate adjustments that did not require the use of approved Phase II methodologies.[348] In addition, in Decision 2013-270 the Commission clarified that these rate adjustments would be calculated using forecast billing determinants, and that there would be no subsequent true-up to account for differences between the forecast billing determinants and actual billing determinants.[349]

The Commission considers that PBR is unrelated to the requirement to periodically update rates through a Phase II process. However, during the PBR term, the distribution utilities may, subject to the provisions of Section 4.3 of this decision, file applications for Phase II adjustments to their rate design and cost allocation methodologies and the Commission will make a determination at that time as to whether the adjustments are warranted.

[347] Decision 2012-237, paragraphs 971, 977 and 982.

[348] Decision 2013-072: 2012 Performance-Based Regulation Compliance Filings AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc., Proceeding 2130, Application 1608826-1, March 4, 2013, paragraph 65.

[349] Decision 2013-270: 2012 Performance-Based Regulation Second Compliance Filings AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc., Proceeding 2477, Application 1609367, July 19, 2013, paragraph 21.

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August 21, 2015

To: Parties currently registered on Proceeding 20414

Generic Proceeding to Establish Parameters for the Next Generation of Performance-based Regulation Plans
Proceeding 20414

Final issues list

1. On May 8, 2015, the Alberta Utilities Commission issued Bulletin 2015-10[1] (bulletin), initiating the current generic proceeding and seeking comments on the parameters to be considered with respect to the next generation of performance-based regulation (PBR) plans. The Commission indicated that parties may register to participate in this generic proceeding by filing a statement of intent to participate (SIP) by May 22, 2015.

2. SIPs were received from the following parties: AltaGas Utilities Inc. (AltaGas or AUI), AltaLink Management Ltd. (AltaLink), ATCO Electric Ltd. (ATCO Electric), ATCO Gas and Pipelines Ltd. (ATCO Gas), Devon Canada, ENMAX Power Corporation (ENMAX), EPCOR Distribution & Transmission Inc. (EPCOR), FortisAlberta Inc. (Fortis), the Consumers' Coalition of Alberta (CCA), the City of Calgary (Calgary), and the Office of the Utilities Consumer Advocate (UCA). Throughout this letter, the utilities regulated under the current PBR framework approved in Decision 2012-237,[2] namely: AltaGas, ATCO Electric, ATCO Gas, EPCOR and Fortis, will be referred to as "the companies." Calgary, the CCA and the UCA will be referred to as "the customer groups."

3. As set out in the bulletin, the Commission anticipates that regulatory efficiencies in preparing submissions, retaining expert witnesses and budgeting of resources could result from a clarification of the relevant issues to be considered in this generic proceeding. Accordingly, in an attachment to the bulletin, the Commission included a preliminary list of issues for parties to comment on. In accordance with the Commission's schedule, parties submitted their comments on the preliminary list of issues by June 5, 2015. Parties filed reply submissions by June 19, 2015. The customer groups filed a joint submission and reply submission.

4. The bulletin indicated that after considering parties' submissions, the Commission would issue a final issues list for this generic proceeding to determine the parameters of the next generation PBR plans. In the sections that follow, the Commission will consider parties'

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[1] Bulletin 2015-10: Generic proceeding to establish parameters for the next generation of performance-based regulation plans, May 8, 2015.
[2] Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

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submissions on the draft issues list before establishing the final scope for this generic proceeding.

The undersigned has been authorized by the Commission to communicate the Commission's determinations on the final issues list.

(1) Submissions of the parties on draft issues list

5. The companies pointed out that parties have had less than three full years of experience under the PBR framework approved in Decision 2012-237, with only the first year of the plan (2013) nearing completion of the process for the final true-up of capital trackers. The companies stated it may not be meaningful to assess the success of the existing PBR plans as suggested by the first issue on the draft issues list until at least the effects of the full five-year PBR term are known.[3] ENMAX expressed a similar view and indicated that "it is premature to evaluate the successes and challenges of the current PBR plan, …in order to explore options for the next generation of PBR plans."[4]

6. Furthermore, given the considerable time and resources invested to develop the parameters of the existing PBR plans, the companies stated that consideration should be given to extending the term of the current plans. In the event that the term of the current plans is not extended, the ATCO companies proposed that the scope of the review be limited to identifying potential improvements to the current PBR plan mechanisms, not wholesale changes to the structure of the plans.[5] AltaGas[6] and EPCOR[7] expressed a similar view. In a similar vein, Fortis[8] indicated that a review of all the components of the existing PBR plans may not be in the interest of regulatory efficiency. ENMAX expressed its view that "it is too early to begin developing the next generation generic PBR."[9]

7. In their joint submission, the customer groups advocated a review of the PBR plans established in Decision 2012-237 at this time, suggesting that significant changes may be required. The customer groups noted that the companies' returns under PBR exceeded the allowed return in 2013 and 2014, in some cases by a wide margin. According to the customer groups, such returns "more than satisfactorily" achieved PBR Principle 2, which states "[a] PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return."[10] However, the customer groups queried whether PBR Principle 5, which states "Customers and the regulated companies should share the benefits of a PBR plan,"[11] is at risk.[12]

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3 Exhibit 20414-X0015, AltaGas comments, page 1; Exhibit 20414-X0017, ATCO companies comments, page 1; Exhibit 20414-X0014, EPCOR comments, page 1; Exhibit 20414-X0019, Fortis comments, pages 1-2.
4 Exhibit 20414-X0016, EMMAX comments, page 2.
5 Exhibit 20414-X0017, ATCO companies comments, page 2.
6 Exhibit 20414-X0021, AltaGas reply comments, page 2
7 Exhibit 20414-X0014, EPCOR comments, page 1.
8 Exhibit 20414-X0019, Fortis comments, pages 1-2.
9 Exhibit 20414-X0016, EMMAX comments, page 2.
10 Decision 2012-237, paragraph 28.
11 Decision 2012-237, paragraph 28.

8. The customer groups submitted that "it is entirely necessary, as a general proposition, to commence a generic review of the first generation PBR plans."[13] Further, in the customer groups' view, "any extensions to the PBR plan are not necessary or warranted."[14]

9. The customer groups further proposed that, before establishing the parameters of the next generation PBR plans, an assessment of the success or shortcomings of the existing PBR plans as a whole needs to be done as a preliminary matter:

> … By firstly addressing and determining the overall success criteria for first generation PBR, and then assessing the plans against that criteria, parties and the Commission will have a clear platform for and from which to address various provisions of the existing plans in the Generic PBR Proceeding, and also to establish parameters for the next generation of PBR.[15]

10. The customer groups also proposed that rebasing and going-in rates should be dealt with as a second preliminary matter before establishing the parameters of the next generation PBR plans.[16] This recommendation is dealt with in Section 2 below.

11. Other than with respect to the X factor and the capital tracker mechanism discussed below, none of the parties made submissions on specific elements of the current plans. The customer groups raised an issue regarding the calculation of return under Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.[17] This issue raised by the customer groups is addressed in Section 5 below.

Commission views

12. The Commission agrees with the companies' view that the limited experience to date under the PBR plans makes an evaluation of the success of the plans and an assessment of any changes to the fundamentals of the plans difficult. Parties have had less than three full years of experience under the current PBR framework, with only the first year of the plans nearing completion of a full capital tracker true-up cycle with the approval of compliance filings by some of the companies. In their comments, the customer groups acknowledged that the companies have only completed two full operating years under the current PBR framework and, therefore, parties only have two years of filings under Rule 005. They also acknowledged that the 2013-2015 capital tracker compliance filing process is not yet completed for three (ATCO Electric, ATCO Gas and Fortis) of the five companies under PBR.[18]

13. The Commission does not share the customer groups' view that company returns for 2013 and 2014, by themselves, indicate that the existing PBR plans should be subject to significant revision in the current proceeding. The PBR plans are designed to provide the

12 Exhibit 20414-X0023, Customers' reply comments, pages 3-4.
13 Exhibit 20414-X0023, Customers' reply comments, page 4.
14 Exhibit 20414-X0023, Customers' reply comments, page 8.
15 Exhibit 20414-X0018, Customers' comments, page 3.
16 Exhibit 20414-X0018, Customers' comments, page 4.
17 Rule 005: Annual Reporting Requirements of Financial and Operational Results, January 1, 2015.
18 Exhibit 20414-X0018, Customers comments, pages 2-3.

companies with incentives to pursue productivity improvements and to lower costs. These incentives may result in higher returns for a company, which the company is allowed to keep for a certain period of time. While the company is pursuing higher returns induced by productivity improvements and lower costs, the customers benefit from rate increases being limited by the PBR formula. Ultimately, customers will share in the benefits received from productivity improvements and lower costs achieved by the company during rebasing. In addition, in accordance with the provisions of the PBR plans approved in Decision 2012-237, if a company's return exceeds the specified threshold amount, the plan may be reopened.

14. In these circumstances, a complete review of the success of the existing PBR plans based on achieving all of the objectives for the plans as set out in Decision 2012-237 or a reconsideration of all elements of the plans, would neither be an efficient use of time and resources, nor is it likely to result in a meaningful, well-considered exercise at this time. Accordingly, the Commission will not undertake an assessment of the success of all of the various provisions of the existing PBR plans, nor will it consider a restructuring of a majority of the components of the plans at this time. The Commission expects to review the success of the PBR plans in meeting the objectives of PBR and consider possible major alternations to the entirety of the plans only when sufficient experience has been gained under the plans and sufficient information is available to undertake such an assessment. Therefore, any such review process will be initiated at a later date, within the context of a continuing PBR regime.

15. While the Commission agrees with the companies that a substantial restructuring of the current plan is not necessary at this time, it does not consider that the present proceeding is entirely premature and that the existing plans should be extended for some period of time as proposed by the companies. While there has been only a limited time frame within which to consider the entire operation of the PBR plans, the Commission considers, after reviewing the submissions of the parties, that some elements of the current plans should be evaluated in the current proceeding.

16. Accordingly, the next generation PBR plans will commence, subject to possible rebasing considerations, following the expiration of the current PBR term, and the parameters of the next generation plans will be unaltered, with the exception of any changes arising from the elements to be considered in this proceeding. For the reasons set out in the sections of this letter that follow, the Commission considers that the present generic proceeding should be focused on three main issues: (i) rebasing and the going-in rates for the next PBR term, (ii) the X factor, and (iii) the treatment of capital. Each of these issues is discussed below.

(2) Rebasing and the establishment of going-in rates

17. This item, from the preliminary issues list, offered for discussion various methods for a rebasing of utility costs and for the establishment of going-in rates for the next generation PBR plans. Related considerations, such as the starting date of the new plan, were also highlighted.

18. As referenced in Section 1 above, the customer groups proposed that the issue of rebasing and going-in rates be dealt with as a preliminary matter, before establishing the parameters of the next generation PBR plans. Specifically, the customer groups were concerned that testing of the

issues identified for rebasing and going-in rates in the generic proceeding at the same time as, and along with, plan-specific parameters, would be problematic as it will impose a substantial regulatory burden for the customer groups dealing with all of the companies at the same time.[19]

19. In addition, the customer groups submitted that the distinction between rebasing and a year of cost-of-service, as set out in Issue 2(c) of the draft issues list, is not clear. The customer groups expressed their understanding that rebasing is shorthand for a redetermination of rates as calculated on a cost-of-service basis and requested further clarification on this matter.[20]

20. In their respective submissions, ENMAX[21] and Fortis[22] agreed with the customer groups that the issue of rebasing and going-in rates should be a preliminary matter. ENMAX observed that rebasing and going-in rates are areas for which there is currently no practical guidance. However, as they are critical components to the launch of next generation PBR, and as they will likely play a role in the incentive properties of next generation PBR, they should receive immediate consideration.[23]

21. The ATCO companies did not oppose the customer groups' general view that the matter of rebasing and the establishment of going-in rates could be addressed as a preliminary matter. As well, the ATCO companies shared the customer groups' concerns with the possibility of all utilities undertaking complex rebasing applications in the same year. The ATCO companies also confirmed their understanding that the method of establishing going-in rates will be determined in this generic proceeding, but that any process related to rebasing or the establishment of going-in rates would be the subject of utility-specific, separate proceedings.[24]

22. EPCOR expressed its view that a preliminary proceeding for rebasing is unnecessary. EPCOR submitted that with a well-defined scope, the proceeding to establish the next generation PBR plans, including rebasing and the establishment of going in rates, can advance effectively and efficiently as currently contemplated in the Commission's preliminary process schedule set out in Bulletin 2015-10.[25]

23. In its submission on the rebasing and going-in rates issue, AltaGas commented on the rebasing versus plan extension options included in the draft issues list. AltaGas pointed out that it does not see the two as being mutually exclusive. Rather, once the extension period is complete, the issue of rebasing and commencement of the future PBR term would arise.[26] Additionally, AltaGas proposed to include an additional item to the rebasing issue, which read "Timing and incorporation of results arising from Phase II proceedings."[27]

[19] Exhibit 20414-X0018, Customers' comments, page 4.
[20] Exhibit 20414-X0018, Customers' comments, page 6.
[21] Exhibit 20414-X0020, ENMAX reply comments, page 2
[22] Exhibit 20414-X0024, Fortis' reply comments, page 2.
[23] Exhibit 20414-X0020, ENMAX reply comments, page 2.
[24] Exhibit 20414-X0020, ATCO companies' reply comments, page 2.
[25] Exhibit 20414-X0025, EPCOR reply comments, page 2.
[26] Exhibit 20414-X0015, AltaGas comments, pages 3-4.
[27] Exhibit 20414-X0015, AltaGas comments, page 4.

Commission views

24. All parties agreed that the issue of rebasing and establishing going-in rates is relevant in developing the next generation PBR plans. ENMAX pointed out that this issue is "a critical component to the launch of next generation PBR, and … it will likely play a role in the success of next generation PBR" plans.[28] The Commission agrees. Accordingly, this issue will be included in the final issues list, with some modifications as set out below.

25. The Commission does not accept, however, the view of the customer groups, also supported by ENMAX and Fortis, that the issue of rebasing should be dealt with as a preliminary matter to this proceeding before consideration of other second generation PBR issues. The Commission confirms the ATCO companies' understanding that this generic proceeding will only consider the methodology for rebasing and establishing going-in rates. The actual rebasing and the establishment of going-in rates in accordance with the approved methodology will be dealt with in subsequent, utility-specific proceedings.[29]

26. In their submission, the customer groups also requested clarification on the distinction between rebasing within the PBR term versus a year of cost of service following the PBR term. On this issue, the Commission observes that having a year of cost-of-service regulation between PBR plans, as was done for ENMAX and referenced by the customers,[30] is not the only method to do rebasing. The Commission is interested in exploring other approaches to rebasing as evidenced by the matters raised under Issue 2 of the draft issues list. The Commission considers that, depending on the method of rebasing adopted, the regulatory burden to complete the rebasing may be reduced, the perverse incentives of rate base rate of return applications may be minimized and the incentive properties of the PBR plan may be enhanced. Therefore, the Commission encourages parties to consider these factors in their future submissions on the methodology for rebasing as set out in the new Issue 1(c) of the final issues list.

27. In its submission, AltaGas commented on the rebasing versus plan extension options included in the draft issues list. Since the Commission determined in Section 1 that it will not consider extending the term of the current PBR plans, the options dealing with plan extensions will not be included in the final issues list.

28. As well, AltaGas proposed that the rebasing and going-in rates issue be augmented with an additional item, which deals with the timing and incorporation of results arising from Phase II proceedings. No party objected to the inclusion of this issue. The Commission considers the issue of how to reflect any Phase II implications in the going-in rates to be important. This proposed addition has been included in the attached final issues list.

(3) Productivity offset (X factor) in the next generation of PBR

29. This issue deals with how to determine the X factor and whether modifications are required to the stretch factor in the next generation of PBR.

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28 Exhibit 20414-X0020, ENMAX reply comments, page 2.
29 Exhibit 20414-X0020, ATCO companies' reply comments, page 2.
30 Exhibit 20414-X0018, Customers' comments, page 4.

30. In Bulletin 2015-10, the Commission indicated that at this time, it does not intend to retain the services of an independent consultant to produce a revised total factor productivity (TFP) study, as was done in Proceeding 566.[31] The customer groups requested that the Commission reconsider this issue in light of their budget constraints and the limited number of experts that can undertake a TFP study. The customer groups stated:

> Accordingly, the Customers respectfully request that the Commission reconsider its position and retain NERA to perform an update to its last TFP study.
>
> Failing that, Customers respectfully request that the Commission, based on its past experience and the relevant findings in the last PBR decision, provide further direction to all parties as to what type of evidence would be of assistance to the Commission.[32]

31. In its submission, EPCOR agreed that the productivity offset (X factor) should be included as an issue in the next generation of PBR. Regarding the customer groups' comments, EPCOR stated that "it is the Commission's prerogative to determine whether or not it will retain an expert in that regard, and [there is] no need for the Commission to retain an expert if the Commission doesn't believe it to be necessary for purposes of the matters to be addressed in this generic proceeding."[33]

32. Parties did not provide any further comments in this issue.

Commission views

33. Despite their divergent positions on whether the Commission should retain an expert to perform a TFP growth study, the customer groups and EPCOR did not object to the inclusion of the issue of setting an X factor in the final scope of the proceeding.

34. In Decision 2012-237, the Commission approved an X factor of 1.16 per cent based on a TFP of 0.96 and a stretch factor of 0.2 per cent. While the Commission will not sponsor a new TFP growth study at this time, the Commission will consider potential changes to the X factor in this proceeding. The Commission recognizes that the X factor is distinct from the TFP growth number, and, as such, will consider evidence with respect to the X factor even if a revised TFP growth study is not available on the record of this proceeding. Finally, the value of the stretch factor in a next generation PBR plan is a new issue meriting consideration in this proceeding and shall remain on the final issues list.

(4) Treatment of capital additions

35. This issue relates to the treatment of capital under PBR. As set out in the draft list of issues, various approaches to this issue may be considered, including the elimination of supplemental capital funding, maintaining the capital tracker status quo, modifying the existing capital tracker mechanism and finding an alternative for the existing capital tracker methodology.

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31 Bulletin 2015-10, paragraph 9.
32 Exhibit 20414-X0018, Customers' comments, page 7.
33 Exhibit 20414-X0025, EPCOR reply comments, page 2.

36. On this issue, AltaGas stated that:

> The need for capital trackers has been thoroughly reviewed and tested in multiple proceedings since initiation of PBR. Unless substantial changes are envisioned to the PBR mechanisms and plans (e.g. removal of capital from PBR), reopening this issue would be counter to the prudent and efficient regulation.
>
> …
>
> Moreover, as with the PBR formula, AUI submits such a broad review or potential redesign is premature given the limited time under which the current system has been in place.[34]

37. Additionally, AltaGas proposed that an additional item be added to this issue:

> (iii) Other systemic mechanisms to incent project cost efficiencies and minimize regulatory burden. AUI submits further consideration might be given to streamlining options, particularly for multi-year capital tracker programs.[35]

38. The customer groups agreed that this issue should be considered in this generic proceeding. However, the customer groups objected to AltaGas' proposal referenced above and indicated "no determination should be made on this point, at least until the evaluation and testing in the proceeding is complete."[36]

39. ENMAX stated the following:

> … With respect to the Capital Tracker component of the plans, there is insufficient experience to fully assess the forecast and true-up processes. For example, the Commission has only recently set out directives with respect to minimum filing requirements for Capital Tracker applications in Decision 3558-D01-2015. Further, it is EPC's view that robust and sufficient testing of forecast and actual capital-related scenarios has yet to take place in the context of PBR and Capital Trackers. Therefore, a significant level of uncertainty remains with respect to sufficient recovery of capital related costs under PBR vis-a-vis Section 122 of the Electric Utilities Act.[37]

40. Parties did not provide any further comments on this issue.

Commission views

41. While ENMAX appeared to object to revisions to the current capital tracker mechanism at this time, the customer groups agreed that this issue should be considered in this generic proceeding. AltaGas was open to reviewing this matter but only if "substantial changes are envisioned to the PBR mechanisms and plans."[38]

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[34] Exhibit 20414-X0015, AltaGas' comments, pages 4-5.
[35] Exhibit 20414-X0015, AltaGas' comments, page 6.
[36] Exhibit 20414-X0023, Customers' reply comments, page 9.
[37] Exhibit 20414-X0020, ENMAX reply comments, page 1.
[38] Exhibit 20414-X0015, AltaGas comments, page 4.

42. In Decision 2012-237 the Commission stated:

> 550. The Commission shares the concerns raised by NERA and interveners that a capital factor must be carefully designed in order to maintain the efficiency incentives of PBR, and also to avoid double-counting. At issue are the types and levels of capital expenditures that can reasonably be expected to be recovered through the I-X mechanism. The Commission finds that a mechanism that permits the recovery of specific types of capital outside of the I-X mechanism should be included in a PBR plan. In the sections of this decision that follow, the Commission addresses these issues by adopting a capital factor that, to the greatest extent possible, seeks to maintain the incentive properties of PBR and avoids double-counting.[39]

43. 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.

44. 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. These modifications could include, as suggested by AltaGas, streamlining options, particularly for multi-year capital tracker programs. Accordingly, the Commission has included the treatment of capital under PBR in the final issues list.

(5) Rule 005 requirements and calculation of annual returns

45. In their submission, the customer groups recommended that the issues list for this generic proceeding should include the method and principles by which annual returns are calculated.

> As noted above, there are instances where approval for a capital tracker is not received until well after the work is completed. This raises the question of how returns should be calculated for the purposes of the PBR plans. For example, assume a utility with one project which was completed in 2013. Assume rates in 2013 were 60% interim rates which were collected in 2013 and the balance was collected in 2014. For reporting purposes and for purposes of the re-opener thresholds, how should the returns for 2013 and 2014 respectively be calculated? Should 100% of the revenue attributable to the asset be recorded in 2013 or should it be 60% in 2013 and 40% in 2014.[40]

46. In their respective response comments, all companies, including ENMAX, responded that changing Rule 005 reporting is outside the scope of this proceeding. The companies pointed out

[39] Decision 2012-237, paragraph 550.
[40] Exhibit 20414-X0018, Customers' comments, page 7.

that Rule 005 applies to all companies, not only those under PBR. Therefore, any changes to Rule 005 reporting should be addressed through the established stakeholder consultation processes the Commission uses with respect to its rules.[41]

Commission views

47. The Commission agrees that changes to Rule 005 are outside the scope of this proceeding because Rule 005 requirements apply to all companies, not only those under PBR. Any changes to Rule 005 should be addressed through the established stakeholder consultation processes the Commission uses with respect to its rules.

48. However, the Commission sees merit in further discussion of the customer groups' submissions, in the context of clarifying the reopener parameters for a next generation PBR plan, since the timing of capital tracker and annual rate adjustment approvals may complicate the assessment of utility returns for purposes of the reopener provisions of the PBR plans. Therefore, the Commission has included the issue of calculating the returns for reopener purposes in the final issues list.

(6) Procedural matters and schedule

49. As a result of the Commission's deliberations on the above issues, the final issues list for this proceeding is focused on topics related to three main issues: (i) rebasing and going-in rates, (ii) X factor, and (iii) the treatment of capital, as set out in the attachment to this letter. As a result of this scoping exercise for the generic proceeding, the Commission has determined that the remaining parameters of the current PBR plans will not be reviewed in this proceeding. The parameters of the current PBR plans not specifically addressed in the final issues list will continue into and form part of the next generation PBR plans to be implemented, subject to possible rebasing considerations, at the end of the current PBR term.

50. As of this time, the Commission does not consider that the preliminary schedule for this generic proceeding set out in Bulletin 2015-10 requires modifications. In accordance with that schedule, parties are invited to make their submissions with respect to the matters identified on the final issues list set out in the attachment to this letter, by **February 29, 2016.**

51. If you have any questions, please contact the undersigned by phone at 403-592-4502 or by email at brian.mcnulty@auc.ab.ca.

Sincerely yours,

Brian C. McNulty
Associate General Counsel

Attachment

[41] Exhibit 20414-X0021, AltaGas' reply comments, page 2; Exhibit 20414-X0022, ATCO Companies' reply comments, page 3; Exhibit 20414-X0025, EPCOR reply comments, paragraph 10; Exhibit 20414-X0020, ENMAX reply comments, page 2; Exhibit 20414-X0024, Fortis' reply comments, page 2.

Attachment

Proceeding 20414
Next Generation PBR Plans
Final issues list

1. Rebasing and the establishment of going-in rates:
   (a) How should going-in rates be set for the next PBR term?
   (b) Is it necessary to rebase prior to the next generation of PBR? What would rebasing involve?
   (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.
   (d) How should the efficiency carryover mechanism approved in the first generation PBR plans[42] be incorporated into the rebasing process or next generation PBR plans?
   (e) Timing and incorporation of results arising from Phase II proceedings.

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

3. Treatment of capital additions:
   (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?
   (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.[43]
      (ii) Modifying the X factor to accommodate the need for higher capital spending (a form of building-blocks PBR plan).[44]

[42] Decision 2012-237, paragraph 775.
[43] Decision 2012-237, Section 7.3.2.1.
[44] Decision 2012-237, Section 7.3.2.2.

(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).[45]

(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).[46]

(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.[47]

(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.[48]

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

4. Calculation of returns for reopener purposes (Rule 005 returns vs. "final" returns based on the actual capital tracker amounts).

[45] Decision 2012-237, Section 7.3.2.3.
[46] Proceeding 2131, 2013 Capital Trackers, Exhibit 0225.02.EDTI-2131, EPCOR opening statement, paragraph 16.
[47] Decision 2012-237, paragraph 610; Proceeding 2131, 2013 Capital Trackers, Exhibit 0225.02.EDTI-2131, EPCOR opening statement, paragraph 15.
[48] Decision 2012-237, paragraph 614.