Decision **26354-D01-2021**

Alberta Utilities Commission

Process to Establish 2023 Rates for Alberta Electric and Gas Distribution Utilities

June 18, 2021

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Published by the:
Alberta Utilities Commission
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1 Decision summary

1. In this decision, the Alberta Utilities Commission sets out how it will process the 2023 cost-of-service (COS) applications that will be filed by the electric and gas distribution facility owners (DFOs or utilities). The Commission has prescribed the minimum level of detail each application is expected to include to support the utilities' 2023 revenue requirement forecasts, but will not prescribe a specific methodology for developing their 2023 revenue requirement forecasts. Instead, the Commission will adopt a hybrid methodology for assessing the 2023 forecasts where the extent to which expenditures are examined is guided by the nature, size or complexity of the associated cost to facilitate a streamlined review of the upcoming 2023 COS applications. The Commission also prescribes filing dates for these applications. This decision provides the Commission's reasons for these determinations.

2 Background and procedural summary

2. Rates for the electric and natural gas distribution utilities under the Commission's jurisdiction are currently set according to the performance-based regulation (PBR) plans established in Decision 20414-D01-2016 (Errata).[1] These plans are effective from January 1, 2018, to December 31, 2022, and apply to the four electric DFOs: ATCO Electric Ltd., FortisAlberta Inc., ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc.; and the two natural gas DFOs: ATCO Gas and Pipelines Ltd., and Apex Utilities Inc. (formerly AltaGas Utilities Inc.).

3. On March 1, 2021, the Commission issued Bulletin 2021-04[2] where it indicated its intention to engage the DFOs and consumer groups to structurally assess the approach to distribution rate regulation in Alberta following the expiration of the current PBR plans. The Commission initiated two related streamlined processes: (i) review and assessment of legacy PBR performance; and (ii) a COS review to establish 2023 rates. This proceeding relates to the second process.

4. In Bulletin 2021-04, the Commission informed stakeholders of its determination to conduct a one-year COS review based on 2023 forecast costs. The Commission commenced the present Proceeding 26354 to determine alternatives for streamlining the traditional line-by-line review of utilities' forecast costs, while meeting the objectives set out in the bulletin: (i) to identify efficiencies achieved by the DFOs during the 2018-2022 PBR term and pass the benefits on to customers; (ii) realign the DFOs' costs and revenues and examine the DFOs' forecast costs and rates to ensure they are reflective of the economic situation in Alberta; and (iii) assess actual

[1] Decision 20414-D01-2016 (Errata): 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, February 6, 2017.

[2] Bulletin 2021-04, Stakeholder consultations to evaluate performance-based regulation in Alberta and to determine process to establish 2023 rates for distribution facility owners, March 1, 2021.

DFO costs in the 2018-2022 PBR term for the purposes of approving 2023 opening rate base and to ensure forecasts are justified based on the prior-period actuals. Further, the Commission stated that the rates approved for 2023 under this COS review may be used as going-in rates for any subsequent PBR term; therefore, parties in their submissions also referred to the 2023 review as the "rebasing" process.

5. Each of the above-mentioned six DFOs, as well as the following intervening parties: The City of Calgary, the Consumers' Coalition of Alberta (CCA), and the Office of the Utilities Consumer Advocate (UCA) were pre-registered as participants in the proceeding. Other parties who registered to participate were the Alberta Federation of Rural Electrification Associations, Lionstooth Energy, the Alberta Electric System Operator, and the Industrial Power Consumers Association of Alberta (IPCAA).

6. In this proceeding, the Commission asked for submissions on the following three issues:

(i) The information and level of detail the 2023 COS applications should contain to facilitate the objectives discussed in the bulletin, while also permitting for a streamlined COS review.

(ii) The form of streamlined review that the Commission can employ to set just and reasonable rates for 2023 without engaging in a traditional line-by-line review of all prior actual and forecast costs. The Commission provided several approaches for consideration (discussed in Section 3), and invited parties to provide their own proposals.

(iii) Application filing, process and timelines to ensure that prospective rates are approved in time for the January 1, 2023, implementation.

7. The Commission's determinations on each of these issues, along with other issues raised by parties in the course of this proceeding, are discussed in the sections of this decision that follow.

8. In addition to receiving parties' submissions on the above issues, the process for this proceeding also included reply comments on recommendations made by other parties and a round of information requests (IRs) from the Commission to all proceeding participants. The record for this proceeding closed on May 14, 2021.

9. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references 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 Form of streamlined review

10. In this proceeding, the Commission asked for submissions on three possible approaches to establish the 2023 revenue requirement for each of the six DFOs:

(i) A mechanistic calculation to determine the 2023 forecast through either an indexing of the lowest cost year of the present 2018-2022 PBR term (as was done for operations and maintenance (O&M) costs in the prior rebasing after the first 2013-2017 PBR term), using an average of actual costs, indexing 2022 actual costs, or extrapolating expenditure trends from the present PBR term into 2023.

(ii) A top-down assessment of the reasonableness of an overall cost for a particular broad category of costs; for example, examining total O&M costs, replacement capital, growth capital, etc., without scrutinizing individual items comprising these broad cost categories.

(iii) Assessment of costs on a hybrid basis, where the review of expenditures would be guided by the nature, size or complexity of spending, while other capital and O&M costs could be assessed in a more streamlined manner described in the first two approaches above.

11. The majority of parties expressed their preference for option (iii), a hybrid approach under which each DFO would employ its own methodology to determine O&M and capital expenditures. EPCOR and ENMAX asserted that no specific forecasting methodology should be prescribed.

12. Calgary and the CCA supported a traditional COS review process, although the CCA alternatively indicated its preference for a high-level analysis, which would evaluate historical net revenue and costs with no examination of details.

13. The Commission agrees with the majority of parties and will adopt a hybrid methodology under which the review of expenditures is guided by the nature, size or complexity of the associated cost, allowing the Commission to focus on certain cost categories, while other costs could be assessed in a more streamlined manner. The Commission finds that using this methodology to establish a revenue requirement on a COS basis best achieves the objectives set out in Bulletin 2021-04, while allowing for a streamlined and efficient regulatory process. The Commission agrees with ENMAX's view that each DFO should be allowed to develop its 2023 forecast[3] on its own accord with an understanding that the utility bears the onus of demonstrating and supporting the reasonableness of the elements comprising its revenue requirement. The Commission finds that adopting a hybrid methodology permits DFOs to both streamline their submissions pertaining to costs that are routine or less controversial, and to tailor and focus their 2023 COS applications on complex issues. The Commission further considers that a hybrid methodology achieves an appropriate balance between regulatory efficiency and providing an adequate opportunity for interveners and the Commission to test a utility's case.

14. The Commission intends to conduct a preliminary assessment of each 2023 COS application, and, taking into consideration the submissions on issues provided by interveners in their statements of intent to participate, provide direction on the scope of the review of each application.

[3] Including the use of appropriate cost escalators it deems reasonable, which reflect Alberta specific forecast inflation and customer additions growth, consistent with what is typically used and supported in establishing a revenue requirement under a COS framework.

4 Level of detail for the 2023 COS applications

15. As stated in the previous section, the Commission-approved hybrid approach contemplates that the extent to which expenditures are examined will be guided by the nature, size or complexity of the associated cost. Notwithstanding this determination, and as discussed in the following sections, the Commission has prescribed a particular form of presenting 2023 forecasts by way of a Commission-developed template. A final version of this template will be provided to the DFOs upon completion of their discussions on the uniform approach to grouping capital additions (as set out in Section 4.2). The distribution utilities are directed, at a minimum, to fill out the template as part of their 2023 COS application filings, but they can also supplement their application and/or template with additional information and schedules as they deem necessary.[4]

16. The following two sections contain specific guidelines for presenting capital and O&M costs to allow these to be assessed in a streamlined manner.

4.1 Operating and maintenance costs

17. Apart from Calgary and the CCA, parties preferred a hybrid approach to determine and assess the 2023 forecast O&M expenses. Based on parties' submissions, the Commission prepared and requested parties to provide feedback on a draft schedule for O&M expenses.[5] The schedule was developed using descriptions provided in prior Rule 005[6] filings from electric utilities, where the majority of utilities presented information at a Uniform System of Accounts (USA) level.

18. Parties were divided as to whether the draft schedule struck a reasonable balance between having enough information to achieve the Commission's objectives and increasing regulatory burden by requesting too much detail. IPCAA, Calgary and the UCA were generally supportive of the schedule, whereas the CCA and the utilities, particularly ATCO, Apex and ENMAX, considered the O&M schedule to be overly detailed.

19. The Commission is not persuaded that the draft O&M schedule should be modified for the following reasons. First, the majority of DFOs provide this level of detail in their Rule 005 filings and as such, completing the schedule does not present an unreasonable burden. Second, not all of the USA accounts in the draft schedule will be applicable to every DFO, and each utility will be able to exercise discretion in preparing its O&M schedules (although the level of detail at the USA account level for the applicable accounts must be preserved). Parties may file additional detail if they consider it to be helpful to the Commission.

20. The Commission also agrees with Apex's recommendation to present the Rule 005 level of detail for O&M expenses for the gas utilities and has prepared a separate draft schedule for gas utilities in the template.

21. IPCAA and the UCA proposed that the average number of customers by rate class, total energy used by rate class and the distribution revenue by rate class be included.[7] The

[4] Additional schedules may be added as separate tabs to the Excel workbook template.
[5] Exhibit 26354-X0047, Draft revised rebasing template, Schedule 3.
[6] Rule 005: *Annual Reporting Requirements of Financial and Operational Results.*
[7] Exhibit 26354-X0050, IPCAA IR Response to AUC 26354, PDF page 2; Exhibit 26354-X0053, UCA Responses to AUC – Proceeding 26354, PDF page 3.

Commission finds there is no need for the utilities to provide information at this level, as rebasing focuses on generally realigning overall costs and revenues of a utility as opposed to understanding allocation among rate classes. Additionally, providing information at this level does not align with the streamlined process the Commission wishes to pursue with the 2023 COS applications. Rather, the Commission sees merit in EPCOR's recommendation to assess the three-year average (2018-2020) of actual O&M costs against the 2023 forecast and, similar to the directives in Section 4.2 on capital expenditures, directs the utilities to include the following in their 2023 COS applications:

(i) Comparisons, along with variance explanations, of the 2023 forecast to: (a) 2018-2020 period average; (b) the lowest O&M cost year for the 2013-2017 PBR term; and (c) 2013-2017 period average, as a starting point to support the need for, and explain the level of, proposed 2023 forecast expenditures.

(ii) Explanations of any significant changes in direction for forecast O&M costs as compared to the historical trend.

(iii) A description of what actions were taken to prudently manage the O&M expenditures in the present PBR term that were not taken during the 2013-2017 PBR term and whether these actions will be implemented in 2023 and subsequent years.

(iv) A description of what new actions are proposed to prudently manage 2023 O&M expenditures.

(v) An explanation of how the trends in the Alberta economy and COVID-19 pandemic factors were considered in arriving at the proposed 2023 O&M forecast. This analysis should be both analytically and numerically supported (for example, by comparing the proposed forecast to the Alberta economic outlook by independent sources).

4.2 Capital costs

22. In this section, the Commission addresses the methodology for developing the capital component of the DFOs' 2023 revenue requirement forecasts, examines the need for deferral account treatment for externally driven capital programs and provides capital-related directives to assist the utilities in the preparation of their 2023 COS applications.

23. Similar to the parties' submissions related to O&M costs, all parties, except for the CCA[8] and Calgary,[9] preferred adopting a hybrid approach to determine and assess 2023 forecast capital additions.

8 As per Exhibit 26354-X0031.01, paragraph 70, the CCA recommended an alternate approach that would set the 2023 revenue requirement based on the difference between actual earnings and the approved return on equity.

9 As per Exhibit 26354-X0018, paragraphs 6-9, Calgary submitted that the Commission's objectives could only be met with a detailed review of all accounts provided for in the *Uniform System of Accounts Regulation*, and approaches that streamlined the process would result in adverse effects due to information asymmetry.

24. Although the level of detail and the methodologies varied amongst the proposals,[10] four consistent themes emerged. First, parties suggested that a mechanistic approach can be used for capital programs that are characterized by predictable costs and similar drivers over time. Second, for programs that do not meet these criteria or are new, a more detailed analysis, including supporting documentation, such as business cases, was proposed. Third, Fortis,[11] supported by other utilities in subsequent submissions, proposed a deferral account for capital expenditures that are externally driven. Fourth, utilities submitted that the opening 2023 rate base should be based on actual 2021 and 2022 capital additions to ensure actual revenue and costs are aligned for 2023 and that opening rate base be given placeholder treatment.[12]

25. To reflect actual performance of the DFOs in the last two years of the present PBR plans, the Commission accepts the utilities' request for placeholder treatment for the opening 2023 rate base. However, this will not preclude the Commission from examining any variances between the actual opening 2023 rate base and the placeholder amount in a future proceeding, which could result in 2023 disallowances if the Commission is not persuaded by the evidence that the 2021 and 2022 actual capital additions were prudent.

26. In response to the Commission IR[13] requesting feedback on the draft rebasing template, parties proposed several revisions to the capital-related schedules contained within the template provided by the Commission. The Commission has considered the suggestions made by the parties and will incorporate some of them in the rebasing template schedules once the DFOs' discussions on the uniform approach to grouping capital additions are completed.

27. Regarding the use of mechanistic approaches for determining the 2023 capital additions forecast, as previously stated in Section 3, each utility will develop the capital component of its 2023 revenue requirement forecast on its own accord, with an understanding that the utility bears the onus of demonstrating and supporting the reasonableness of the elements comprising its revenue requirement, and present it in accordance with the format prescribed by the Commission's rebasing template. In their 2023 COS applications, DFOs are expected to demonstrate that their 2023 forecast capital additions, including any forecasts of costs based on proposed mechanistic approaches, will result in just and reasonable rates.

28. The Commission finds that allowing deferral accounts or true-ups for capital programs that are driven by external factors will result in additional subsequent applications, which contradicts the Commission's objective of an efficient regulatory process. The Commission is confident that the utilities have the knowledge and experience to anticipate, plan for, and provide a one-year 2023 forecast for externally driven capital programs and, for these reasons, will not approve deferral account treatment for these programs.

[10] For example, as per Exhibit 26354-X0019, PDF page 2, and Exhibit 26354-X0038, paragraphs 8-9, IPCAA proposed that a review of previous years' costs would be sufficient to assess the 2023 forecast for maintenance capital, while a detailed examination of replacement and growth capital would be required, since its analysis indicated that historical capital expenditures do not reflect customer growth. As per Exhibit 26354-X0023, paragraph 58, the UCA proposed a mechanistic approach for growth capital based on an average of the actual cost per new customer.

[11] Exhibit 26354-X0030, paragraph 58.

[12] For example, as per Exhibit 26354-X0024, paragraph 8, the ATCO Utilities explained the requirement for a placeholder.

[13] Exhibit 26354-X0046, PARTIES-AUC-2021APR30-001.

29. In an IR, the Commission requested that utilities work collaboratively to develop a proposed uniform approach to grouping capital projects/activities into 10-20 higher level categories to achieve consistency among the four electric DFOs and, separately, between the two gas DFOs, and then to further categorize capital programs by "Recurring" and "Non-Recurring," as indicated in the Commission's draft template. Though amenable to meeting and providing the Commission with an update, utilities were reluctant[14] to adopt this approach and were unsure of the Commission's definition of the terms "Recurring" and "Non-Recurring." As well, IPCAA recommended that interveners be allowed to participate in these discussions. The Commission accepts this recommendation and expects the utilities to provide a meaningful opportunity for intervener input and a reasoned acceptance or rejection of intervener proposals.

30. The utilities are directed to incorporate the following criteria during the related meetings and in the preparation of their 2023 COS applications:

(i) As a starting point, use existing capital groupings that were used in K-bar schedules, segregating them into Recurring and Non-Recurring categories, as defined below.

(ii) Group (i.e., aggregate or split) projects or programs into several large categories (programs) in a consistent way among DFOs. Consider a consistent naming convention for similar programs that currently may have different names among the utilities.

(iii) Categorize programs that have predictable stable costs and similar drivers over time into the Recurring capital program list. The Commission may consider a mechanistic approach proposed by a DFO to arrive at the 2023 forecast capital additions for the programs in this category, without further detail or support being required.

(iv) Programs that are new or do not meet the criteria set out for Recurring capital programs should be categorized under Non-Recurring capital. The Commission will require a more detailed analysis, including business cases to support the 2023 forecast capital additions for the programs in this category, subject to the considerations outlined in part (v) below.

(v) The Commission may consider any or all of the following to assess whether further detail or support is required for a proposed project or program:

(a) The materiality criteria as set out in Section 4.3 applied to the difference between the 2023 forecast and the average of the actual capital additions for the period 2018-2020.

(b) The yearly actual capital additions in the period 2013-2020.

(c) The average of the actual capital additions for the period 2018-2020.

14 For example, as per Exhibit 26354-X0056, EDTI-AUC-2021APR30-002, PDF page 11, EPCOR submitted that "forcing consistency in the presentation of capital information across DFOs for the sake of facilitating 'comparability' among DFOs would prove to be a fruitless, although highly burdensome and costly exercise."

(d) The average of the actual capital additions for the period 2013-2017.

(e) Variance explanations that support capital additions that for any year (2013-2020) have varied from additions in other years that appear more predictable.

(f) An explanation that supports the need for a similar quantum of capital expenditures and additions in 2023.

(g) A clear connection to the level of economic activity in Alberta forecast for 2021-2022 and reasonably projected for 2023.

31. To assist the Commission in achieving its objectives for rebasing, while allowing for an efficient regulatory process, the utilities are directed to provide in their 2023 COS applications, at a minimum, the following program level information:

(1) Comparison, along with variance explanations, of the 2023 forecast to: (a) 2018-2020 period average; (b) the lowest capital cost year for the 2013-2017 PBR term; and (c) 2013-2017 period average, as a starting point to support the need for, and explain the level of, proposed 2023 forecast expenditures. Utilities must provide comparisons of their prior year trends in capital expenditures to independent reports of overall gross domestic product and/or other measures of economic performance in Alberta during the same period, to provide a reasonability check for utility capital expenditures.

(2) Explanations of any significant changes in direction for forecast capital costs as compared to the historical trend. Credible third-party economic activity and load forecasts are required.

(3) A description of what actions were taken to prudently manage capital expenditures in the present PBR term that were not taken during the 2013-2017 PBR term and whether these actions will be implemented in 2023 and subsequent years.

(4) A description of what new actions are proposed to prudently manage 2023 capital expenditures.

(5) An explanation of how the trends in the Alberta economy and COVID-19 pandemic were considered in arriving at the proposed 2023 capital forecast. This analysis should be both analytically and numerically supported (for example, by comparing the proposed forecast to the Alberta economic outlook by independent sources).

32. The Commission will give parties until September 1, 2021, to work collaboratively and to develop the proposed uniform approach to reporting capital-related items to be used in the rebasing schedules for reporting purposes in the 2023 COS review applications. As this direction concerns the potential of rearranging capital expenditures into groupings, it should not prevent the utilities from commencing their internal preparations of the 2023 COS applications as soon as practicable. The Commission directs parties to report the outcome of these discussions on the record of this proceeding by way of a post-disposition correspondence. To assist parties in achieving a successful outcome in this collaborative work, Commission staff member(s) may attend the meeting(s) to provide supplementary guidance should parties encounter an

impediment in their progress. Parties must inform the Commission whether they require Commission staff attendance by way of a post-disposition letter in this proceeding.

4.3 Materiality threshold

33. Some parties advocated for the use of materiality thresholds to streamline the review of the 2023 COS applications by limiting detailed reviews of cost categories to those that have seen a material increase or decrease.[15] Parties could not agree on whether to apply the materiality thresholds from Bulletin 2020-25,[16] Rule 005, or some other alternative.

34. Given the objectives identified in Bulletin 2021-04, the Commission agrees with parties that regulatory efficiency could be enhanced if the Commission focuses its examination primarily where costs have materially increased (or decreased) and on new projects. Consequently, the Commission has adopted the following materiality thresholds for testing the 2023 forecast O&M and capital costs, and directs the utilities to apply them in the 2023 COS applications:

(i) O&M costs: Bulletin 2020-25 materiality thresholds will presumptively apply to the O&M costs. If the 2023 forecast is greater than the 2018-2020 actual average O&M cost by more than the Bulletin 2020-25 materiality thresholds, then the utilities are required to provide explanations for positive or negative material variances of the forecast.

(ii) Capital costs: Where a forecast 2023 capital addition for a capital program is greater than the 2018-2020 actual average capital cost by more than the Rule 005 variance explanation thresholds, utilities are required to provide an explanation for positive or negative material forecast variances, as well as a business case.

35. Notwithstanding that the materiality thresholds will be used to assess the 2023 forecast O&M and capital costs, the utilities should briefly explain how they arrived at the 2023 forecast numbers, even for the variances below the materiality thresholds. The Commission notes that it may examine any cost, particularly if it has novel implications. For example, if a cost is close or just under a materiality threshold line, the Commission may choose to further examine this cost if there is a unique circumstance or precedential import.

4.4 Identification and quantification of efficiencies

36. One of the guiding PBR principles used by the Commission is that “customers and the regulated companies should share the benefits of a PBR plan.”[17] The Commission considers that this principle remains an important consideration when establishing 2023 rates through a COS review. One of the objectives of the 2023 COS review identified in Bulletin 2021-04 was the

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[15] Exhibit 26354-X0028, APEX reply submission, paragraph 24; Exhibit 26354-X0042, APEX reply submission, paragraphs 12-13; Exhibit 26354-X0018, Calgary submission, paragraphs 6 and 19; Exhibit 26354-X0035, CCA reply submission, paragraphs 13-15; Exhibit 26354-X0026, ENMAX submission, paragraphs 61-63; Exhibit 26354-X0027, EPCOR submission, paragraphs 23-32; Exhibit 26354-X0030, Fortis submission, paragraphs 40-48; Exhibit 26354-X0023, UCA submission, paragraph 78.

[16] Bulletin 2020-25, Reducing regulatory burden with materiality thresholds for review of cost of service rate applications, July 3, 2020, sets out the materiality thresholds to review O&M variance only in COS rate applications.

[17] Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012, paragraph 28.

identification of efficiencies achieved by the DFOs during the 2018-2022 PBR term and passing the benefits on to customers.

37. Over the current PBR term, the financial results achieved by the DFOs suggest that they have achieved efficiencies to reduce their costs. However, to what degree the observed financial results are related to efficiency improvements, rather than other factors, is unclear. The Commission considers that for customers to benefit from the efficiencies achieved by the DFOs during the current PBR term, cost savings from these efficiencies must be passed on to customers in 2023 rates.

38. With the exception of ENMAX, the DFOs and the interveners suggested various ways by which efficiencies achieved in the current PBR term could be passed on to customers in the 2023 rates:

- ATCO,[18] Fortis[19] and [20]Apex all generally submitted that a forecasting approach based on an average of costs over the current PBR term (for predictable or stable cost categories) would result in achieved efficiencies being passed on to customers.

- EPCOR submitted that in its 2023 COS application, it would identify efficiencies achieved during the current PBR term and ensure they are reflected in its 2023 revenue requirement.[21]

- The UCA submitted that using a lowest cost year approach to forecasting 2023 O&M costs would result in passing on to customers all of the O&M efficiencies achieved during the PBR term.[22]

- The CCA opined that each utility should identify and quantify the efficiencies it achieved. Any interested party or the Commission could also identify any efficiencies achieved by the DFOs. Once identified, the efficiencies could be tested and quantified to assess whether the benefits are being passed on to customers.[23]

39. The Commission expects that utilities tracked and monitored their expenditures in various accounts, or cost centres, as a normal course of managing their businesses. In the Commission's view, where costs have changed or trended in a certain direction, DFOs should be in a position to explain what has caused the changes, be it an internal cost-reducing action, or the result of external factors. Further, DFOs should be able to quantify the outcomes of the initiatives they undertook. For example, if a DFO undertook a number of initiatives to reduce its inspection costs, while it may not be able to quantify how each specific initiative impacted the costs, it should be able to quantify how its inspection costs have changed over time and what portion of those reductions are attributable to efficiency initiatives.

18 Exhibit 26354-X0024, ATCO Utilities 2023 COS Review Submission, paragraph 45.
19 Exhibit 26354-X0030, FortisAlberta Letter and Submission on 2023 COS Review, paragraph 48.
20 Exhibit 26354-X0028, AUI Comments on 2023 COS Review, paragraphs 27, 28, and 46.
21 Exhibit 26354-X0027, EDTI Written Submission, paragraph 34.
22 Exhibit 26354-X0023, UCA Comments on 2023 cost of service, paragraph 53.
23 Exhibit 26354-X0031.01, CCA Submission 26354 COS, paragraph 5.

40. Accordingly, in their 2023 COS applications, DFOs are directed to:

- Quantify and clearly demonstrate how the efficiencies found, and cost reductions achieved, during the current PBR term are reflected in their forecast revenue requirement, and will be passed on to customers.

- Where O&M expenses at the USA level or capital programs have experienced material cost decreases (relative to 2017 notional amounts for O&M costs or annual total capital funding for capital programs) that are not attributable to the identified efficiencies, the DFO should explain what has caused the decreased costs observed and quantify the costs.

41. If a DFO is not able to satisfactorily demonstrate to the Commission how cost reductions will be flowed through to its customers in its forecast 2023 revenue requirement, the Commission may consider a more mechanistic, high-level approach to ensure ratepayers benefit from the efficiencies achieved during the PBR term. For example, the Commission observes that in Proceeding 26356, IPCAA suggested that earnings above the approved return on equity should be considered as a general indicator and a starting point for quantifying the achieved efficiencies.[24] The Commission considers that reductions to 2023 revenue requirement on the account of efficiencies achieved during the present PBR term would provide consumers with the benefits of PBR, and meet its foundational principles. This is particularly important for Alberta consumers since the PBR plans have not incorporated annual earnings sharing mechanisms in the past.

4.5 Prudence review

42. In Bulletin 2021-04, the Commission determined that it would include the assessment of prudence of actual costs incurred during the 2018-2022 PBR term as part of its one-year COS review based on 2023 forecast costs.

43. The utilities expressed concern with the reference to an "assessment of prudence" in the bulletin and stated that a prudence review should not occur because actual costs incurred under the incentives of PBR are presumed to be prudent. They added that such a review would be inconsistent with the PBR framework, and the potential for this type of after-the-fact review was never previously communicated by the Commission.[25]

44. One of the fundamental differences between the present PBR plan and the 2013-2017 PBR plan is the absence of the capital tracker funding mechanism in its legacy form. The capital tracker funding mechanism in the 2013-2017 PBR plan applied to the majority of the DFO's capital-related costs and resembled a traditional COS review process. When this mechanism was replaced with an "envelope" funding type of approach in the current PBR plan through the K-bar factor, utilities were provided with the majority of capital funding on the basis of a pre-determined formula; this capital was not subject to the same level of Commission scrutiny that was applied to the capital tracker program expenses.

[24] Proceeding 26356, Evaluation of PBR in Alberta, Exhibit 26356-X0019, paragraph 7.
[25] Exhibit 26354-X0027, EPCOR written submission, paragraph 12; Exhibit 26354-X0024, ATCO written submission, Section 4.4.1; Exhibit 26354-X0026, ENMAX written submission, Section 3.3; Exhibit 26354-X0042, Apex reply comments, paragraph 10; Exhibit 26354-X0044, FortisAlberta reply submission, paragraph 50.

45. The Commission maintains its view that actual costs incurred under the incentives of PBR should generally be deemed prudent and not be subjected to the same level of assessment as expenditures under COS regulation. However, given that all capital expenditures were managed under the K-bar funding envelope with no Commission scrutiny under the 2018-2022 PBR plan, the Commission may require the DFOs to demonstrate the reasonableness of the costs of certain programs.

5 Other matters

5.1 Pre-filing of historical data

46. The Commission considers that timely completion of the COS proceedings in the compressed timeframe available will be aided through the pre-filing of historical DFO data for 2013 to 2020. Accordingly, the Commission directs each DFO to file on the record of its respective proceeding such historical data, using the rebasing template format reflective of the developed capital groupings, at least one month prior to the deadline date for 2023 COS application filings set out in Table 1 of Section 6 of this decision.

5.2 Depreciation studies and technical updates

47. Similar to the views expressed in a prior rebasing proceeding that led to the establishment of the present 2018-2022 PBR plans, some utilities (e.g., ATCO Electric and ATCO Gas (ATCO Utilities), Apex and Fortis[26]) suggested a need to file a complete or abridged form of a depreciation study, or technical update, as part of the 2023 COS applications.

48. In the Commission's view, consideration of depreciation and other similar COS studies in conjunction with a review of 2023 COS applications will hinder the Commission's objective of promoting regulatory efficiency and achieving a streamlined rebasing process. As such, depreciation applications, or technical updates, will be considered outside the forthcoming 2023 COS applications. However, to ensure that a DFO's 2023 rates are reflective of the most up-to-date information and to minimize future true-ups, the Commission is prepared to approve the updated depreciation costs on a placeholder basis in COS review proceedings for those utilities that wish to update their depreciation parameters. These placeholders may be adjusted as a result of the Commission's review of the 2023 COS applications. Similar to the Commission's findings on this matter in Decision 20414-D01-2016 (Errata),[27] each DFO will be given an opportunity to file its depreciation application following the completion of the COS review process, at which point the depreciation parameters approved as part of the DFO's 2023 forecast will be trued up to reflect any disallowances in the Commission's decision.

49. Lastly, ENMAX explained that it intends to file depreciation and cost allocation studies as part of its forthcoming 2023-2025 transmission COS application. ENMAX requested that the Commission approve placeholders for depreciation and allocated costs in its 2023 COS application, and conduct the testing of these studies in the forthcoming transmission COS application. Once the studies have been tested and approved by the Commission, ENMAX suggested that the distribution placeholders could be trued up. Because reviewing the depreciation amounts applied for in the transmission COS application will not add additional

[26] Exhibit 26354-X0024, ATCO Utilities, paragraph 65; Exhibit 26354-X0028, AUI, paragraph 39; Exhibit 26354-X0030, 2021-03-22 Fortis Letter and Submission on 2023 COS Review, paragraphs 50-51.
[27] Decision 20414-D01-2016 (Errata), paragraph 70.

complexity to the 2023 COS rebasing proceeding or result in a delay to that proceeding, the Commission approves ENMAX's proposal to use the depreciation parameters filed in its DFO COS application on a placeholder basis, subject to the outcome of ENMAX's 2023-2025 transmission COS application.

5.3 Billing determinant forecast

50. The 2023 billing determinant forecast should be developed using Commission-approved methodologies for each DFO, unless there is a valid reason for departure, in which case, a detailed explanation for such departure should be provided. As well, the 2023 billing determinant forecast should reflect the rate class allocation last approved in each DFO's respective Phase II proceeding. Each utility is directed to provide an analytical and numerical explanation of how the Alberta economy and COVID-19 pandemic factors were considered in arriving at the proposed 2023 billing determinant forecast.

5.4 Investment level changes

51. The ATCO Utilities proposed that utilities be given the opportunity to include changes to investment levels in their 2023 COS applications.[28] The Commission finds that to facilitate an efficient regulatory process and to minimize regulatory burden associated with undertaking a review of six COS applications, it will not allow changes to investment levels to be included in the 2023 COS applications. Further, the Commission has previously indicated that maximum investment levels are among the matters to be considered in the initiative announced in Bulletin 2021-09[29] to standardize the terms and conditions of electric distribution utilities' connection process.

5.5 Deferral accounts

52. The Commission confirms ATCO Utilities' expectation that currently approved deferral accounts and rate riders shall continue to be applied in the 2023 COS year, subject to clarification provided by the Commission in paragraph 28 of this decision. The differences between forecast and actual costs for items in these accounts will be subsequently trued up. In this respect, placeholder treatment will also be afforded to those 2021 and 2022 costs requiring alignment to establish the 2023 opening rate base.

5.6 ATCO Utilities' IT costs

53. In Decision 20514-D02-2019,[30] the Commission directed specific reductions to the prices set out in the IT master services agreements (MSAs) between the ATCO Utilities (transmission and distribution) and Wipro Solutions Canada Limited for inclusion in each of the regulated utilities' revenue requirements, as follows:

> 379. In summary, to account for the considerations listed above and to achieve just and reasonable rates, adjustments to the MSA pricing are required. The ATCO Utilities are directed to apply (i) a reduction of 13 per cent in MSA pricing in year 1 (which automatically flows through to all subsequent years as in the example shown above); and

28 Exhibit 26354-X0024, paragraph 67.
29 Bulletin 2021-09, Stakeholder consultation to standardize terms and conditions of electric distribution utilities' connection process, April 29, 2021.
30 Decision 20514-D02-2019: The ATCO Utilities (ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd.), Information Technology Common Matters Proceeding, Proceeding 20514, June 5, 2019.

(ii) a glide path reduction in MSA pricing of 4.61 per cent (on a weighted average across towers) in each of years 2 through 10.

54. In the same decision, the Commission determined that rates during the 2018-2022 PBR term did not need to be adjusted to reflect approved IT costs for the distribution utilities. However, the ATCO Utilities were required to incorporate the findings of Decision 20514-D02-2019 for the purpose of calculating 2018 going-in rates as part of the rebasing exercise at the time.[31] Consistent with these findings, the Commission directs the ATCO Utilities to reflect the Commission's disallowance in Section 6 of Decision 20514-D02-2019 in the calculation of their 2023 forecast revenue requirement, taking into consideration any impact of the disallowance on O&M, capital and indirect capital.

55. ATCO Gas and ATCO Electric are further directed to show the calculations of disallowances and to clearly show the directed IT disallowance on an annual basis by capital, indirect capital, and O&M in the applicable rebasing schedules.

6 Timing

56. The Commission will assess the 2023 COS applications in pairs, in a staggered manner in accordance with the schedule set out in Table 1 below. This schedule will best alleviate the concerns of significant regulatory burden and workflow constraints associated with undertaking COS reviews of six DFOs simultaneously and still provide certainty to DFOs and customers through prospective ratemaking. The staggered approach should also ease intervener resource constraints in participating in the three proceedings. Finally, this approach will allow for better comparability (to the extent possible) between the utilities paired in each proceeding.

Table 1. COS application timelines

Utility	Date of application submission	Proceeding number
ATCO Electric	November 15, 2021	26615
Fortis	November 15, 2021	
ATCO Gas	December 15, 2021	26616
Apex	December 15, 2021	
ENMAX	January 17, 2022	26617
EPCOR	January 17, 2022	

57. For parties' convenience, the Commission has established the 2023 COS proceedings and pre-registered each utility in the relevant proceeding (as set out in the table above).

7 Order

58. It is hereby ordered that:

(1) Each of Apex Utilities Inc., ATCO Electric Ltd. (distribution), ATCO Gas and Pipelines Ltd. (distribution), ENMAX Power Corporation (distribution), EPCOR

[31] Decision 20514-D02-2019, paragraph 392.

Distribution & Transmission Inc. (distribution) and FortisAlberta Inc. shall file a 2023 cost-of-service application in accordance with the directions set out in this decision and the timelines in Table 1.

(2) At least one month prior to its date of 2023 cost-of-service application submission, each utility shall pre-file historical 2013-2020 data using the rebasing template format in its corresponding proceeding.

(3) By September 1, 2021, the distribution utilities must inform the Commission of the outcome of their collaborative work to develop a uniform approach to categorizing capital programs.

Dated on June 18, 2021.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

(original signed by)

Douglas A. Larder, QC
Vice-Chair

(original signed by)

Kristi Sebalj
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Apex Utilities Inc. (Apex or AUI)
ATCO Electric Ltd. Bennett Jones LLP
ATCO Gas
ENMAX Power Corporation (ENMAX)
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) Borden, Ladner Gervais LLP
FortisAlberta Inc. (Fortis)
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors
Independent System Operator (ISO)
Industrial Power Consumers Association of Alberta (IPCAA)
Lionstooth Energy
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Russ Bell & Associates Inc. Brownlee LLP

Alberta Utilities Commission

Commission panel
C. Dahl Rees, Chair
D.A. Larder, QC, Vice-Chair
K. Sebalj, Commission Member

Commission staff
C. Wall (Commission counsel)
A. Jukov
A. Ayri
A. Corsi
E. Deryabina
B. Edwards
D. Fedoretz
C. Robertshaw

Appendix 2 – 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. As stated in the previous section, the Commission-approved hybrid approach contemplates that the extent to which expenditures are examined will be guided by the nature, size or complexity of the associated cost. Notwithstanding this determination, and as discussed in the following sections, the Commission has prescribed a particular form of presenting 2023 forecasts by way of a Commission-developed template. A final version of this template will be provided to the DFOs upon completion of their discussions on the uniform approach to grouping capital additions (as set out in Section 4.2). The distribution utilities are directed, at a minimum, to fill out the template as part of their 2023 COS application filings, but they can also supplement their application and/or template with additional information and schedules as they deem necessary. .... paragraph 15

2. IPCAA and the UCA proposed that the average number of customers by rate class, total energy used by rate class and the distribution revenue by rate class be included. The Commission finds there is no need for the utilities to provide information at this level, as rebasing focuses on generally realigning overall costs and revenues of a utility as opposed to understanding allocation among rate classes. Additionally, providing information at this level does not align with the streamlined process the Commission wishes to pursue with the 2023 COS applications. Rather, the Commission sees merit in EPCOR's recommendation to assess the three-year average (2018-2020) of actual O&M costs against the 2023 forecast and, similar to the directives in Section 4.2 on capital expenditures, directs the utilities to include the following in their 2023 COS applications:

   (i) Comparisons, along with variance explanations, of the 2023 forecast to: (a) 2018-2020 period average; (b) the lowest O&M cost year for the 2013-2017 PBR term; and (c) 2013-2017 period average, as a starting point to support the need for, and explain the level of, proposed 2023 forecast expenditures.

   (ii) Explanations of any significant changes in direction for forecast O&M costs as compared to the historical trend.

   (iii) A description of what actions were taken to prudently manage the O&M expenditures in the present PBR term that were not taken during the 2013-2017 PBR term and whether these actions will be implemented in 2023 and subsequent years.

   (iv) A description of what new actions are proposed to prudently manage 2023 O&M expenditures.

   (v) An explanation of how the trends in the Alberta economy and COVID-19 pandemic factors were considered in arriving at the proposed 2023 O&M forecast. This analysis should be both analytically and numerically supported (for example, by comparing the proposed forecast to the Alberta economic outlook by independent sources).

   ....paragraph 21

3. The utilities are directed to incorporate the following criteria during the related meetings and in the preparation of their 2023 COS applications:

   (i) As a starting point, use existing capital groupings that were used in K-bar schedules, segregating them into Recurring and Non-Recurring categories, as defined below.

   (ii) Group (i.e., aggregate or split) projects or programs into several large categories (programs) in a consistent way among DFOs. Consider a consistent naming convention for similar programs that currently may have different names among the utilities.

   (iii) Categorize programs that have predictable stable costs and similar drivers over time into the Recurring capital program list. The Commission may consider a mechanistic approach proposed by a DFO to arrive at the 2023 forecast capital additions for the programs in this category, without further detail or support being required.

   (iv) Programs that are new or do not meet the criteria set out for Recurring capital programs should be categorized under Non-Recurring capital. The Commission will require a more detailed analysis, including business cases to support the 2023 forecast capital additions for the programs in this category, subject to the considerations outlined in part (v) below.

   (v) The Commission may consider any or all of the following to assess whether further detail or support is required for a proposed project or program:

      (a) The materiality criteria as set out in Section 4.3 applied to the difference between the 2023 forecast and the average of the actual capital additions for the period 2018-2020.

      (b) The yearly actual capital additions in the period 2013-2020.

      (c) The average of the actual capital additions for the period 2018-2020.

      (d) The average of the actual capital additions for the period 2013-2017.

      (e) Variance explanations that support capital additions that for any year (2013-2020) have varied from additions in other years that appear more predictable.

      (f) An explanation that supports the need for a similar quantum of capital expenditures and additions in 2023.

      (g) A clear connection to the level of economic activity in Alberta forecast for 2021-2022 and reasonably projected for 2023.

....paragraph 30

4. To assist the Commission in achieving its objectives for rebasing, while allowing for an efficient regulatory process, the utilities are directed to provide in their 2023 COS applications, at a minimum, the following program level information:

   (1) Comparison, along with variance explanations, of the 2023 forecast to: (a) 2018-2020 period average; (b) the lowest capital cost year for the 2013-2017 PBR term; and (c) 2013-2017 period average, as a starting point to support the need for, and explain the level of, proposed 2023 forecast expenditures. Utilities must provide comparisons of their prior year trends in capital expenditures to independent reports

of overall gross domestic product and/or other measures of economic performance in Alberta during the same period, to provide a reasonability check for utility capital expenditures.

(2) Explanations of any significant changes in direction for forecast capital costs as compared to the historical trend. Credible third-party economic activity and load forecasts are required.

(3) A description of what actions were taken to prudently manage capital expenditures in the present PBR term that were not taken during the 2013-2017 PBR term and whether these actions will be implemented in 2023 and subsequent years.

(4) A description of what new actions are proposed to prudently manage 2023 capital expenditures.

(5) An explanation of how the trends in the Alberta economy and COVID-19 pandemic were considered in arriving at the proposed 2023 capital forecast. This analysis should be both analytically and numerically supported (for example, by comparing the proposed forecast to the Alberta economic outlook by independent sources). ....paragraph 31

5. The Commission will give parties until September 1, 2021, to work collaboratively and to develop the proposed uniform approach to reporting capital-related items to be used in the rebasing schedules for reporting purposes in the 2023 COS review applications. As this direction concerns the potential of rearranging capital expenditures into groupings, it should not prevent the utilities from commencing their internal preparations of the 2023 COS applications as soon as practicable. The Commission directs parties to report the outcome of these discussions on the record of this proceeding by way of a post-disposition correspondence. To assist parties in achieving a successful outcome in this collaborative work, Commission staff member(s) may attend the meeting(s) to provide supplementary guidance should parties encounter an impediment in their progress. Parties must inform the Commission whether they require Commission staff attendance by way of a post-disposition letter in this proceeding. .... paragraph 32

6. Given the objectives identified in Bulletin 2021-04, the Commission agrees with parties that regulatory efficiency could be enhanced if the Commission focuses its examination primarily where costs have materially increased (or decreased) and on new projects. Consequently, the Commission has adopted the following materiality thresholds for testing the 2023 forecast O&M and capital costs, and directs the utilities to apply them in the 2023 COS applications:

(i) O&M costs: Bulletin 2020-25 materiality thresholds will presumptively apply to the O&M costs. If the 2023 forecast is greater than the 2018-2020 actual average O&M cost by more than the Bulletin 2020-25 materiality thresholds, then the utilities are required to provide explanations for positive or negative material variances of the forecast.

(ii) Capital costs: Where a forecast 2023 capital addition for a capital program is greater than the 2018-2020 actual average capital cost by more than the Rule 005 variance explanation thresholds, utilities are required to provide an explanation for positive or negative material forecast variances, as well as a business case. ....paragraph 34

7. Accordingly, in their 2023 COS applications, DFOs are directed to:

- Quantify and clearly demonstrate how the efficiencies found, and cost reductions achieved, during the current PBR term are reflected in their forecast revenue requirement, and will be passed on to customers.
- Where O&M expenses at the USA level or capital programs have experienced material cost decreases (relative to 2017 notional amounts for O&M costs or annual total capital funding for capital programs) that are not attributable to the identified efficiencies, the DFO should explain what has caused the decreased costs observed and quantify the costs.

....paragraph 40

8. The Commission considers that timely completion of the COS proceedings in the compressed timeframe available will be aided through the pre-filing of historical DFO data for 2013 to 2020. Accordingly, the Commission directs each DFO to file on the record of its respective proceeding such historical data, using the rebasing template format reflective of the developed capital groupings, at least one month prior to the deadline date for 2023 COS application filings set out in Table 1 of Section 6 of this decision. .... paragraph 46

9. The 2023 billing determinant forecast should be developed using Commission-approved methodologies for each DFO, unless there is a valid reason for departure, in which case, a detailed explanation for such departure should be provided. As well, the 2023 billing determinant forecast should reflect the rate class allocation last approved in each DFO's respective Phase II proceeding. Each utility is directed to provide an analytical and numerical explanation of how the Alberta economy and COVID-19 pandemic factors were considered in arriving at the proposed 2023 billing determinant forecast.
.... paragraph 50

10. In the same decision, the Commission determined that rates during the 2018-2022 PBR term did not need to be adjusted to reflect approved IT costs for the distribution utilities. However, the ATCO Utilities were required to incorporate the findings of Decision 20514-D02-2019 for the purpose of calculating 2018 going-in rates as part of the rebasing exercise at the time. Consistent with these findings, the Commission directs the ATCO Utilities to reflect the Commission's disallowance in Section 6 of Decision 20514-D02-2019 in the calculation of their 2023 forecast revenue requirement, taking into consideration any impact of the disallowance on O&M, capital and indirect capital.
.... paragraph 54

11. ATCO Gas and ATCO Electric are further directed to show the calculations of disallowances and to clearly show the directed IT disallowance on an annual basis by capital, indirect capital, and O&M in the applicable rebasing schedules. .... paragraph 55