Alberta Utilities Commission

# ATCO Gas
# Apex Utilities Inc.

## 2023 Cost-of-Service Review

**September 1, 2022**

**Alberta Utilities Commission**
Decision 26616-D01-2022
ATCO Gas
Apex Utilities Inc.
2023 Cost-of-Service Review
Proceeding 26616

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# 1 Decision summary

1. This decision provides the Alberta Utilities Commission's determinations in respect of the 2023 cost-of-service (COS) applications of ATCO Gas, a division ATCO Gas and Pipelines Ltd., and Apex Utilities Inc. In reaching its decision the Commission has reviewed the 2023 forecast costs of ATCO Gas and Apex that underlie their respective rates in 2023. Further, the rates approved for 2023 on a forecast cost basis will also serve as going-in rates for the third term of performance-based regulation (PBR3) that will commence on January 1, 2024.

2. The primary purpose of this proceeding is to assess (on a forward-looking basis) the reasonableness of the 2023 forecast costs of ATCO Gas and Apex, with a view to realigning their rates with their costs prior to the start of their respective PBR3 terms in 2024. Because 2023 is an intervening COS rebasing year that falls between two PBR terms, the approach taken by the Commission in reviewing these two applications involved examining and duly considering not only those matters and issues typically encountered in, or associated with, traditional COS or rate base rate-of-return regulation proceedings, but also the types of matters, issues and incentives more likely to require scrutiny during the rebasing process under PBR.

3. Many of the Commission's observations and findings in this decision, and the language used to articulate them, are similar to those set out in Decision 26615-D01-2022, dealing with the 2023 COS applications for ATCO Electric Ltd. and FortisAlberta Inc.[1] The distribution utilities involved in these proceedings are subject to the same, or very similar, incentives because they are currently regulated under the same PBR plan, tailored, as needed, to the circumstances of each utility. Moreover, all distribution utilities adopted a similar approach in preparing their 2023 COS applications, consistent with Commission directions, and used comparable approaches to forecast their respective 2023 revenue requirements, particularly ATCO Electric and ATCO Gas. The latter two utilities also filed similar applications. Intervener proposals were likewise generally consistent in these proceedings. As a result, some aspects of this decision are similar to Decision 26615-D01-2022.

4. For the reasons set out in this decision, the Commission makes the following findings.

5. The Commission largely accepts the hybrid methodologies put forward by ATCO Gas and Apex, which use mechanistic and non-mechanistic approaches to arrive at their respective 2023 forecasts. Under the mechanistic approach, the utilities forecast costs by calculating the average of actual costs incurred in the 2018 to 2020 period and then escalating that average by certain proposed escalation factors such as inflation and customer growth. Under the non-

[1] Decision 26615-D01-2022: ATCO Electric Ltd., FortisAlberta Inc., 2023 Cost-of-Service Review, Proceeding 26615, July 28, 2022.

mechanistic approach, the utilities forecast from the bottom up, which is a traditional way to forecast costs under COS regulation.

6. The Commission directs the following adjustments to the applied-for escalation factors:

(a) Both ATCO Gas and Apex are to use their actual labour cost increases for the period 2019-2020 in calculating their inflation escalators.

(b) Both ATCO Gas and Apex are to reduce their proposed customer growth escalator by 15 per cent.

7. The Commission directs each of ATCO Gas and Apex to recalculate their respective 2023 forecasts under the mechanistic approach to reflect the escalation factors approved in this decision.

8. As set out in the Commission's letter dated April 8, 2022, in Proceeding 26615, information technology (IT) and customer information system (CIS) costs are addressed in this decision for both ATCO Electric and ATCO Gas (collectively referred to as the ATCO Distribution Utilities).

9. The Commission finds ATCO Gas's 2023 operating and maintenance (O&M) and capital additions forecasts to be reasonable, subject to the incorporation of the approved escalation factors and the following O&M and capital disallowances:

**Table 1. O&M and capital disallowances for ATCO Gas**

| Program | Disallowance | Amount ($ million) |
|---|---|---|
| **O&M** | | |
| Emissions Reduction and Energy Efficiency Program | Entire program | 0.86 |
| **Capital** | | |
| Information Technology | Partial (IBM/Kyndryl forecast) | 2.49 |
| **Total disallowances** | | **3.35** |

10. The Commission finds Apex's 2023 O&M and capital additions forecasts to be reasonable, subject to the incorporation of the approved escalation factors and the following O&M and capital disallowances:

**Table 2. O&M and capital disallowances for Apex**

| Program | Disallowance | Amount ($ million) |
|---|---|---|
| **O&M** | | |
| Shared corporate services costs | Partial | 0.7 [Note 1] |
| **Capital** | | |
| Athabasca gas supply | Entire program | 3.27 |
| **Total disallowances** | | **3.97** |

Note 1: Estimated amount not including the effects of removing any TriSummit Utilities Inc. (TSU) employee short-term incentive plan (STIP) costs and changing the percentage allocator to Apex. TSU is the parent company to Apex.

11. In light of the foregoing, each of ATCO Gas and Apex must submit a compliance filing by October 3, 2022, to reflect the directions and findings in this decision. ATCO Electric is required to reflect the disallowances set out in this decision in its September 26, 2022, compliance application, as directed by the Commission in Decision 26615-D01-2022.

12. Based on the record of this proceeding, and having applied its experience, expertise and judgment in carrying out its mandate to set just and reasonable rates under both COS and PBR frameworks, the Commission is satisfied that the forecast 2023 revenue requirements of each of the utilities, as adjusted by the Commission in this decision, will result in just and reasonable rates.

13. Specifically, the Commission is satisfied that 2023 rates (to be established following the Commission's review and consideration of the compliance filings) based on the forecast 2023 revenue requirements approved in this decision will allow the utilities a reasonable opportunity to recover their expected costs of providing utility service, including a reasonable opportunity to earn the approved rate of return on their invested capital.

14. The Commission reviewed the entire record in coming to this decision; lack of reference to a matter addressed in evidence or argument does not mean that it was not considered. This decision addresses the contentious cost items forecast in the applications, including updates, and any matters that the Commission has otherwise determined need to be specifically addressed. If a matter is not specifically addressed in this decision, it is because the Commission finds the applied-for costs or cost treatment associated with the matter to be reasonable and the applicants' request is therefore approved as filed, subject to the Commission's findings on escalation factors. All directions in this decision are subject to all findings and other directions made elsewhere in this decision.

# 2 Introduction and background

15. Rates for the electric and natural gas distribution utilities under the Commission's jurisdiction are currently set according to the PBR plans established in Decision 20414-D01-2016 (Errata).[2] These plans are effective from January 1, 2018, to December 31, 2022, and apply to the four large electric distribution facility owners (DFOs) in Alberta: ATCO Electric, Fortis, ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc.; and the two large natural gas DFOs in Alberta: ATCO Gas and Apex (formerly AltaGas Utilities Inc.). This is the second PBR plan in Alberta for all of the DFOs, with the exception of ENMAX.[3] For ease of reference the Commission will refer to the second (and still current) PBR plan as the PBR2 plan.

16. There were many references in this proceeding to the first PBR plan established in Decision 2012-237[4] which was in place from 2013 to 2017. For ease of reference, the Commission will refer to that PBR plan as the PBR1 plan.

17. Under both the PBR1 and PBR2 plans, each utility's rates (or revenue-per-customer in the case of the two gas DFOs) are adjusted annually by means of an indexing mechanism that tracks the rate of inflation (I factor), less an offset to reflect the productivity improvements the

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

[3] ENMAX was under formula-based ratemaking (a form of PBR) from 2007 to 2013. 2014 was a COS rebasing year, after which ENMAX joined the other utilities in their PBR plan from 2015 to 2017. ENMAX is currently regulated under the 2018-2022 PBR plan. For DFOs other than ENMAX, the first term took place from 2013 to 2017, followed by the current 2018-2022 PBR term.

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

DFO is expected to achieve during the PBR plan period (X factor), plus other specific adjustments. As a result, with the exception of specifically approved adjustments, during a PBR term, a utility's revenues are no longer linked to its costs. This decoupling of costs and revenues is intended to promote behaviours that increase productivity and decrease costs. At the end of a PBR plan, costs and revenues are typically realigned through a process referred to as "rebasing."[5] The rebasing process determines new rates, referred to as "going-in rates," that will be used for the next PBR term.

18. On March 1, 2021, the Commission issued Bulletin 2021-04[6] where it expressed its intention to engage the DFOs and consumer groups to assess the approach to distribution rate regulation in Alberta following the expiration of the current PBR2 plans.

19. In Bulletin 2021-04, the Commission indicated that following the expiration of the current PBR plans in 2022, it was necessary to review the DFOs' costs and revenues to achieve the following objectives: (i) 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 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 prior-period actual costs.

20. The Commission initiated two related streamlined processes: (i) a review and assessment of legacy PBR performance; and (ii) a COS review to establish 2023 rates.

21. In its review and assessment of legacy PBR performance in Decision 26356-D01-2021,[7] the Commission found that, on balance, PBR achieved many of the objectives that were set out in the founding PBR principles.[8] The Commission found it to be in the public interest that the distribution utilities return to a third PBR plan (PBR3) commencing in 2024, upon completion of the 2023 COS year, provided that certain improvements were incorporated into their PBR3 plans. The Commission has since initiated Proceeding 27388 to determine the parameters of the PBR3 plans. The Commission also determined that it would proceed with a one-year COS review based on 2023 forecast costs.

22. The current proceeding was constituted to conduct that one-year COS review for the two natural gas DFOs, ATCO Gas and Apex. In addition, this proceeding included an assessment of prudence of actual costs incurred to date by the DFOs in the PBR2 term. This decision also addresses the applications for IT and CIS costs for both ATCO Electric (which filed its application in Proceeding 26615) and ATCO Gas.[9] In the instances where it refers to both ATCO Electric and ATCO Gas, the Commission uses the term the "ATCO Distribution Utilities."

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5 As explained in Decision 20414-D01-2016 (Errata), paragraph 26, 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).

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

7 Decision 26356-D01-2021: Evaluation of Performance-Based Regulation in Alberta, Proceeding 26356, June 30, 2021.

8 Decision 26356-D01-2021, PDF page 25, paragraph 82.

9 Proceeding 26615, Exhibit 26615-X0426, AUC letter - Process and scope for oral questioning and oral argument, paragraphs 5-6.

The Commission also uses the term "the ATCO Utilities" to refer to ATCO Electric Transmission and ATCO Electric Distribution, divisions of ATCO Electric Ltd.; ATCO Gas and ATCO Pipelines, divisions of ATCO Gas and Pipelines Ltd.; and "ATCO" to refer to the parent company of the regulated utilities, ATCO Ltd.

23. Under the COS regulatory framework, a regulator first determines the total amount of money required by a utility to provide its regulated services in a year. This is referred to as the revenue requirement, and it is made up of the total annual operating, maintenance and administrative expenses of the company plus the utility's capital-related costs (depreciation, interest on debt, and return on equity (ROE)). Rates are then established by dividing the revenue requirement for each customer class by the billing units (such as the monthly charge, or dollars per kilowatt hour).

24. To enhance regulatory efficiency and to address the significant regulatory burden associated with COS reviews, the Commission initiated a proceeding to determine streamlined alternatives to the traditional line-by-line review of utilities' forecast costs. In the resulting Decision 26354-D01-2021,[10] the Commission adopted a hybrid approach for the review and assessment of the 2023 revenue requirements for each of the six DFOs. Under this approach, 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 assessing other costs in a more streamlined manner. It is important to note, however, that while the Commission permitted the utilities to use mechanistic approaches in developing their 2023 forecasts, it neither approved nor endorsed any specific mechanistic approach. The Commission made it clear that the utilities are to demonstrate that their cost forecasts, "including any forecasts of costs based on proposed mechanistic approaches, will result in just and reasonable rates."[11]

25. The Commission determined that it would assess the 2023 COS applications in pairs, in a staggered manner, to alleviate concerns about regulatory burden and workflow constraints. The Commission also determined that this approach would allow for better comparability (to the extent possible) between the utilities paired in each proceeding. ATCO Electric and Fortis (Proceeding 26615) were the first utilities to file their applications, followed one month later by ATCO Gas and Apex (the current Proceeding 26616), and ENMAX and EPCOR (Proceeding 26617) filing the month after that.

26. To assist the utilities in preparing their applications, the Commission provided a rebasing template, which set out a format for how the DFOs should present their 2023 cost forecasts in their respective 2023 COS applications. Specific Commission directions on how DFOs were required to file or address operating and maintenance costs, capital costs, materiality thresholds, identification and quantification of efficiencies and disallowances, are described where applicable in the main body of this decision.

[10] Decision 26354-D01-2021: Process to Establish 2023 Rates for Alberta Electric and Gas Distribution Utilities, Proceeding 26354, June 18, 2021.

[11] Decision 26354-D01-2021, paragraph 27.

## 3 Applications summary

27. ATCO Gas and Apex each requested approval of their 2023 revenue requirement forecasts, developed in accordance with the hybrid approach adopted by the Commission in Decision 26354-D01-2021. The hybrid approach involves using mechanistic and non-mechanistic components to forecast 2023 costs. Both utilities stated that a mechanistic forecasting approach is useful when the forecast costs in 2023 are unlikely to deviate from the historical trend. Where there was a significant divergence between the historical trend and forecast 2023 costs, ATCO Gas and Apex employed a non-mechanistic approach.

28. For its mechanistic approach, ATCO Gas restated its historical actual 2018-2020 costs in 2020 dollars by normalizing for inflation and system size using its I factor inflation and annual customer growth escalators. The restated amounts for the three-years were then averaged. Next, these averaged costs were escalated and restated again, this time in 2023 dollars by normalizing for inflation and system size using ATCO Gas's forecast inflation and annual customer growth rates for the 2021-2023 period.[12] For accounts where ATCO Gas applied a mechanistic approach, its view was that the escalated 2018-2020 average is representative of costs reasonably anticipated to be incurred in 2023, and ATCO Gas did not expect these costs to fluctuate significantly from the costs incurred over the 2018-2020 period.[13]

29. For its mechanistic approach, Apex used a three-year average of 2018-2020 actual costs indexed to 2023 dollars using the same formulas as ATCO Gas, but with its own inputs (such as labour costs) to those formulas.[14] The Commission will therefore refer to the results of both ATCO Gas's and Apex's calculations as the "escalated 2018-2020 average."

30. ATCO Gas and Apex relied on a non-mechanistic approach when they considered that the three-year escalated average would not accurately forecast the costs that will be incurred in 2023. They indicated that this methodology is a traditional way to forecast costs under COS regulation and, while more time consuming than a mechanistic approach, allows for an accurate forecast when historical data cannot predict expected 2023 costs because there is an expected divergence from past years, or the forecast cost is not part of the historical cost structure. Where a non-mechanistic methodology was used, ATCO Gas and Apex either explained (i) why the historical trend is not indicative of the costs that are forecast to be incurred in 2023; or (ii) for new programs, why each program was necessary.

31. ATCO Gas forecast the majority of its O&M and Administrative and General (A&G) and capital costs using the mechanistic approach, stating that it tried to maintain historical trends wherever possible. ATCO Gas submitted that this approach allowed it to account for trends in the Alberta economy and for the COVID-19 pandemic by incorporating this historical data.[15] A detailed breakdown of ATCO Gas's 2023 revenue requirement is shown below in Table 3.

12 Exhibit 26616-X0018, ATCO Gas application, paragraph 100.
13 Exhibit 26616-X0018, ATCO Gas application, paragraph 101.
14 Exhibit 26616-X0023, Apex application, paragraphs 77 and 182.
15 Exhibit 26616-X0018, ATCO Gas application, paragraph 35.

**Table 3. ATCO Gas 2023 distribution revenue requirement**

| | ($ million) |
|---|---|
| Return on rate base | 95.4 |
| Interest on long-term debt | 78.4 |
| Return on preferred shares | 2.3 |
| O&M | 242.5 |
| Deprecation and amortization | 239.0 |
| Revenue offset | (24.5) |
| Utility Income Tax | 23.8 |
| **Total** | **$656.7** |

Source: Exhibit 26616-X0193, Schedule 1.0.

32. ATCO Gas's forecast 2023 O&M costs and total revenue requirement are shown in Table 4, along with historical values from the previous five years.

**Table 4. ATCO Gas 2018-2023 summary of revenue requirement**

| | 2018 Actual | 2019 Actual | 2020 Actual | 2021 Actual | 2022 Forecast | 2023 Forecast |
|---|---|---|---|---|---|---|
| | ($000) | | | | | |
| **O&M** | 207,723 | 219,703 | 240,877 | 239,240 | 232,353 | 242,476 |
| **Total revenue (PBR) or requirement (2023)** | 593,593 | 604,691 | 634,483 | 729,021 | 673,222 | 656,741 |

Source: Exhibit 26616-X0193, Schedule 1.0; Total Revenue (PBR) or Revenue Requirement – 2021 Actual Proceeding 25863, Post-Disposition filing Appendix F, Schedule 4.2. 2022 Forecast, Proceeding 26847, Exhibit 26847-X0007, Appendix E, Schedule 4.2.

33. Similarly, Apex forecast the majority of its O&M and capital costs mechanistically[16] but did forecast certain costs non-mechanistically in circumstances where it considered that the use of the escalated 2018-2020 average was inadequate to the task. For such costs, Apex provided additional supporting information to justify the forecasts. A detailed breakdown of Apex's 2023 revenue requirement is shown below in Table 5.

**Table 5. Apex 2023 distribution revenue requirement**

| | ($ million) |
|---|---|
| Return on equity | 15.7 |
| Interest on long-term debt | 12.2 |
| O&M expenses | 47.9 |
| Depreciation and amortization | 26.4 |
| Utility income tax | 0.7 |
| Other revenue | (1.2) |
| Inter-affiliate asset utilization recovery | (1.7) |
| **Total** | **100.0** |

Source: Exhibit 26616-X0197, Schedule 1.

34. Apex's forecast 2023 O&M costs and total revenue requirement are shown in Table 6, along with historical values from the previous five years.

16 Apex indicated that approximately 93 per cent of its O&M costs and 78 per cent of its capital additions (the recurring capital) were forecast under a mechanistic approach.

**Table 6. Apex 2018-2023 summary of revenue requirement**

| | 2018 Actual | 2019 Actual | 2020 Actual | 2021 Forecast/Actual | 2022 Forecast | 2023 Forecast |
|---|---|---|---|---|---|---|
| | ($000) | | | | | |
| **O&M** | 40.8 | 42.3 | 43.1 | 43.3 | 45.5 | 47.9 |
| **Total revenue (PBR) or requirement (2023)** | 76.7 | 83.3 | 87.2 | 90.4 | 94.2 | 100.0 |

Source: 2018-2020 Actual O&M and 2022-2023 Forecast O&M: Exhibit 26616-X0197, Schedule 1; 2021 Actual O&M: Apex 2021 Rule 005 Filing. Total Revenue (PBR) or Revenue Requirement: 2018-2020 Actual and 2023 forecast - Exhibit 26616-X0197, Schedule 1; 2021 Forecast – Proceeding 25867, Exhibit 25867-X0019, Schedule 1.0. 2022 Forecast: Proceeding 26851, Exhibit 26851-X0007, Schedule 1.0.

# 4 2023 forecast review and PBR3 rebasing

## 4.1 Commission's approach to reviewing the applications

35. In this section, the Commission explains its overall approach to reviewing the applications of ATCO Gas and Apex. It is divided into three subsections. The first subsection explains the overall purpose of this proceeding. The second subsection discusses the importance of going-in rates and incentives attending the rebasing process. Finally, the Commission explains how this rebasing is different from the rebasing process used for the PBR2 plans.

### 4.1.1 What is the purpose of this proceeding?

36. The Commission has a statutory mandate to set just and reasonable rates.[17] In exercising this mandate, the Commission must balance the interests of consumers with the interests of utilities. The Supreme Court of Canada described the mandate as requiring the regulator to fix fair and reasonable rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the utility a fair return for capital invested.[18] This means that the rates set by the Commission must give the utility a reasonable opportunity to recover reasonably forecast or prudently incurred operating and capital costs.[19]

37. Historically, the Commission has discharged its rate setting responsibilities using two forms of regulation: traditional COS regulation and, more recently, PBR for distribution utilities. The merits, methods and incentives associated with each regulatory framework have been described by the Commission in its previous decisions.[20] In summary, under a COS regime the regulator reviews the utility's expected costs and permits the recovery through customer rates of only those forecast costs that it has determined to be reasonable. Under a PBR framework, a regulator focuses on prices (i.e., utility rates) and permits the utility to retain all, or a portion of, profits achieved during the PBR term by keeping its costs below revenues resulting from the approved rates.

38. In the current proceeding, the Commission is re-aligning revenues and costs for ATCO Gas and Apex on a forecast basis in 2023 and setting going-in rates for the next PBR period. The approach taken by the Commission here differs from a traditional COS process in at least two important respects. First, traditional COS reviews typically examine every aspect of the applicant

17 *Electric Utilities Act*, Section 122.
18 *Northwestern Utilities Ltd. v Edmonton (City)*, [1929] S.C.R. 186;
19 *Ontario v Ontario Power Generation*, 2015 SCC 44, paragraphs 15-18.
20 See for example Decision 2012-237, sections 1.1 and 1.2.

utility's finances and operations at the same level of detail. And second, the conventional approach to establishing future revenue requirements is to review (detailed) bottom-up cost forecasts. Here, however, the Commission has adopted a hybrid approach to assess the reasonableness of 2023 forecast costs and the revenue requirement that follows from these forecasts. In particular, in this proceeding the Commission's review of expenditures is guided by the nature, size or complexity of the associated cost, which allows the Commission to narrow its focus to certain cost categories, while assessing other cost categories in a more streamlined manner. Consistent with this approach, the Commission here considers a number of cost items (covering large portions of the respective revenue requirements of ATCO Gas and Apex) that were forecast mechanistically – that is, by escalating historical costs rather than by building the forecasts from the bottom up.

39. A final distinction worth noting is that unlike traditional COS proceedings, here, the Commission has considered utility incentives attending the rebasing process under PBR because 2023 is an intervening rebasing year that falls between two PBR terms.

### 4.1.2 Importance of going-in rates and incentives attendant to the rebasing process

40. Six large distribution utilities in Alberta have been regulated under PBR for nearly a decade with the current PBR term finishing at the end of 2022. Over this period, the Commission has gained considerable understanding of, and experience with, the PBR framework and has made observations on the effect of PBR incentives, or lack thereof, on the O&M and capital expenses of the distribution utilities while operating under Commission-approved PBR plans. In past decisions, the Commission has underscored the importance of going-in rates and recognized that there exist certain problematic incentives associated with the rebasing process. The Commission has been mindful of such incentives when reviewing all cost trends and cost forecasts in this proceeding.

41. In Decision 20414-D01-2016 (Errata), the Commission emphasized that getting the going-in rates correct is an important contributor to the success of a PBR plan. In the PBR2 rebasing proceeding, all parties agreed on the need to ensure that a utility's going-in rates are neither too high nor too low, in the sense that they should provide the utility with no more than a reasonable opportunity to earn the approved rate of return.[21] This is because, unlike in a traditional COS rate case where any earnings above or below the approved ROE are limited to a one- or two-year test period, any such over-earning or under-earning that takes place in the rebasing year gets "locked in" as part of the going-in rates and has the potential to influence the achieved ROE throughout the entire PBR term.[22] Parties expressed a similar view in this proceeding and the Commission continues to share this view.

42. With respect to incentives associated with the rebasing process, the Commission has recognized that, generally, a utility's incentive to pursue efficiencies weakens as the end of the PBR term approaches because there is less time remaining for the utility to benefit from any efficiency gains.[23] There is an incentive in the final year of a PBR plan for distribution utilities to

[21] Decision 20414-D01-2016 (Errata), paragraph 34.
[22] Decision 20414-D01-2016 (Errata), paragraphs 32-34. Decision 23604-D01-2019: AUC-Initiated Review Under the Reopener Provision of the 2013-2017 Performance-Based Regulation Plan for the ATCO Utilities, Proceeding 23604, February 27, 2019, paragraph 40.
[23] Decision 2012-237, paragraph 759.

increase their costs so as to increase going-in rates for the next PBR term.[24] This incentive is also present in the rebasing year if going-in rates are set based on the approved costs in that year. Increasing costs in the rebasing year (which are recovered from customer rates), for example by implementing a number of capital projects, may allow the utilities to reap the benefits of, and savings from, such activities during the following PBR term that may not be shared with customers until the next rebasing.

43. The Commission has also recognized 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 prior PBR period.[25] In this proceeding, the interveners drew attention to this incentive and urged the Commission to ensure that the benefit to consumers of efficiencies realized in the previous PBR term are not offset or denied by utilities intentionally over-forecasting costs during the COS review process of realigning (forward-looking) costs with revenues. Given that sharing of benefits of a PBR plan between customers and utilities is one of the Commission's founding PBR principles[26] and is among the stated objectives for this proceeding, this is also an important consideration for the Commission. The Commission specifically requested the utilities 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."[27]

44. In this regard, as discussed throughout this decision, the interveners representing customer groups in this proceeding advocated that the Commission adopt some elements of the PBR2 rebasing approach approved in Decision 20414-D01-2016 (Errata). Specifically, to ensure that customers benefit from the efficiencies achieved during PBR2, the interveners either favoured rebasing based on (i) the lowest cost year approach (as primarily advocated by the UCA); or (ii) retaining some elements of notional rebasing with less reliance on utility forecasts and explicitly implementing efficiency sharing by offsetting forecasts in one of two ways: deducting either the X factor or a lump-sum efficiency offset (as primarily advocated by the CCA) from the 2023 forecast revenue requirement. However, as explained below, for this proceeding the Commission has selected a different method of rebasing.

### 4.1.3 How is this rebasing different from PBR2 rebasing?

45. For the PBR2 plan, the Commission set going-in rates on the basis of a notional 2017 revenue requirement, rooted in actual costs experienced by each DFO during the PBR1 term. This notional revenue requirement was intended to reflect the notional costs each distribution utility would have incurred in 2017 if operating under the incentives of the PBR framework.

46. However, for the current proceeding, the Commission selected a different approach to review costs: a one-year COS review based on 2023 forecast costs to re-establish the link between utilities' costs and rates. Unlike the PBR2 rebasing approach that used the notional revenue requirement on which to base the going-in rates, for the current proceeding each utility was allowed to develop its 2023 revenue requirement forecast understanding that the utility bears

24 Decision 20414-D01-2016 (Errata), paragraph 45.
25 Decision 20414-D01-2016 (Errata), paragraph 43.
26 The AUC five PBR principles are set out in paragraph 28 of Decision 2012-237.
27 Decision 26354-D01-2021, paragraph 40.

the onus of demonstrating and supporting the reasonableness of the elements comprising its revenue requirement.[28]

47. Under the present rebasing approach, if a utility was *not* successful in achieving efficiencies that resulted in cost savings during a PBR plan, or faced any other challenges managing its costs such that its earnings were below the approved ROE, the COS rebasing presents an opportunity for the utility to make its case to the Commission to set rates that will allow it a reasonable opportunity to earn the approved rate of return in the future. As discussed in Section 5.1 of this decision, this was not a concern for either ATCO Gas or Apex because they earned more than their approved ROE in most years of the PBR2 term so far, as they were entitled to do under PBR incentives. That being said, what ATCO Gas and Apex earned or did not earn in the past has no bearing on their statutory right to a reasonable opportunity to earn the approved rate of return in the future.

48. A COS review based on forecast costs allows the utilities to bring forward any new cost pressures or any changing circumstances expected to be experienced in the rebasing year. In this proceeding, parties pointed out that forecast costs are generally impacted by the following:

(i) inflation in labour and other utility cost inputs;

(ii) changes in the size of the distribution system;

(iii) external factors (for example, government policies on net-zero emissions and grid modernization, COVID-19, changes to tax rates, etc.); and

(iv) realized efficiencies.

49. Where the Commission finds forecasts to include unreasonable expenditures, it will disallow such forecast costs and, correspondingly, adjust downward the applied-for future revenue requirement.

50. While the Commission's task in this proceeding is to ensure that 2023 forecast costs are reasonable and reflect the efficiencies achieved and cost reductions realized during the PBR2 term, it does not necessarily follow that the resulting approved distribution revenue requirement will be lower than 2022 costs. New cost pressures may offset the efficiencies achieved during the PBR2 term.

### 4.2 2023 closing rate base and PBR3 going-in rates

51. In the notice of the application issued on December 17, 2021,[29] the Commission indicated that the rates approved for 2023 under this COS review proceeding would be used as going-in rates for the future PBR term that will commence in 2024.

52. The record of this proceeding includes extensive discussion on the rebasing process and the importance of establishing the "correct" going-in rates for the PBR3 term, including the measure of rate base that should be used to set those rates. In Decision 26354-D01-2021, the Commission determined that the actual 2023 opening rate base will be used to fix the 2023 rates.[30] In this proceeding, the Commission asked parties whether the 2023 actual closing rate

[28] Decision 26354-D01-2021, paragraph 13.
[29] Exhibit 26616-X0027, Notice of application, 2023 Cost-of-service review.
[30] Decision 26354-D01-2021, paragraph 25.

base should be used to fix PBR3 going-in rates in 2024 or whether the 2023 forecast closing rate base should be used for this purpose.[31]

53. ATCO Gas suggested that the Commission should defer its consideration of this issue to the proceeding setting the parameters of the PBR3 plans.[32] Similarly, Apex submitted that while it is generally supportive of using actual closing 2023 rate base, the PBR3 going-in rate base used to establish going-in rates should be considered in the context of the full set of PBR3 parameters to be established in Proceeding 27388.[33]

54. In argument, the UCA observed that the actual 2023 closing rate base will not be available until May 2024. The UCA submitted that the going-in rate base for PBR3 in 2024 should therefore be the 2022 actual rate base plus the approved forecast capital additions for 2023.[34] Calgary's view was similar to that of the UCA.[35]

55. For the reasons that follow, the Commission has decided to use forecast 2023 closing rate base (that is, 2022 actual closing rate base plus the forecast capital additions for 2023 approved by the Commission in this decision) to fix ATCO Gas's and Apex's going in rates for PBR3 in 2024.

56. First, using forecast rate base ensures that the utilities' going-in rates are prospective. Actual rate base for 2023 will not be available until May 2024, and the Commission would have to conduct a prudence review of each utility's capital additions costs, which would create regulatory lag connected with finalizing actual rate base for each of ATCO Gas and Apex and, therefore, would extend the final determination of the going-in rates for their PBR plans well into 2024.

57. In the Commission's view, it is important that going-in rates are established on a prospective basis. Prospective rates are important because they enable ATCO Gas and Apex to manage their actual costs to their respective forecasts and to respond to the incentives built into their approved PBR plans. They also provide the utilities and their consumers certainty by avoiding retrospective adjustments to rate base which may be detrimental to both the utilities and their customers.

58. Second, using forecast rate base is consistent with the Commission's approach to setting rates under a COS framework. Under this approach, with the exception of amounts booked into deferral accounts and, therefore, subject to a future true-up, the utilities bear forecast risk for the test period.

59. Third, and related to the above, undertaking a comprehensive assessment and review of forecast costs and rate base (which took place in this proceeding) can be as robust and effective

31 Opening and closing rate base is required due to the mid-year convention for setting rates. The mid-year convention is the accepted method for approximating the cost of capital investments in the year, and for the purposes of calculating other capital-related costs. The mid-year convention uses an arithmetical average of a utility's investments to account for capital-related costs uniformly over the entire year, recognizing that assets are added to rate base throughout the year. It is commonly used in regulatory jurisdictions in North America.
32 Exhibit 26616-X0308, ATCO Gas final argument, paragraph 89.
33 Exhibit 26616-X0311, Apex final oral argument, PDF page 13.
34 Transcript, Volume 5, page 498.
35 Transcript, Volume 5, page 511.

as reviewing actual costs (rate base) once they are available, but with the important benefit of preserving rate prospectivity, which is unavailable under the latter approach.

60. For these reasons, the Commission finds that 2023 rates (based on forecast costs), determined by averaging the 2023 actual opening rate base and 2023 forecast closing rate base approved in this proceeding (subject to the resolution of any approved capital-related deferral accounts) will serve as going-in rates for PBR3. This finding is subject to the following two considerations to be resolved in Proceeding 27388 where the parameters of the PBR3 plans will be established.

61. The first consideration relates to the fact that in setting the PBR3 plans, the Commission expressed interest in implementing PBR rate adjustments on July 1 of each year rather than January 1 as is the current practice. If such a change is made, it will necessitate consideration of how to set rates for the January 1 to June 30, 2024 period.

62. The second consideration is that the actual closing 2023 rate base may be used for any approved capital funding mechanism in PBR3, subject to the decision of the Commission in respect of its examination of the parameters of PBR3 in Proceeding 27388. The Commission notes that all supplemental capital funding mechanisms used in both the PBR1 and PBR2 plans relied on the actual closing rate base in the rebasing year, even though the going-in rates for those plans were set on a different basis (forecast rate base was used for PBR1 and notional rate base for PBR2).

# 5 Issues common to ATCO Gas and Apex

## 5.1 Identification and quantification of efficiencies

63. In this section, the Commission first explains the importance of quantifying the efficiencies achieved by each of the utilities. It then summarizes how the utilities reflected the quantification of efficiencies achieved (to date) throughout the PBR2 term in their applications. Next, the Commission considers alternative proposals presented by interveners on how realized efficiencies should be quantified. Finally, the Commission outlines the evidence establishing both how and why efficiencies actually achieved in the PBR2 period are reflected in the 2023 forecasts approved in this decision.

### 5.1.1 The importance of quantifying efficiencies in this proceeding

64. The identification and quantification of efficiencies achieved by ATCO Gas and Apex during the PBR2 term is one of the key objectives the Commission set for this proceeding. This is because this proceeding serves as the rebasing proceeding following the PBR2 term. The Commission emphasized in prior PBR-related decisions that rebasing plays an important role in sharing the benefits of a PBR plan between the utilities and their customers, as required by one of the foundational PBR principles identified by the AUC.[36]

65. Specifically, the Commission opted not to include in the PBR2 plan (and the PBR1 plan before it) an earnings-sharing mechanism (ESM). The Commission noted that during the PBR term, customers automatically share in the expected efficiency gains because these are built into

[36] Decision 2012-237, paragraph 28.

rates through the X factor (inclusive of the stretch factor) regardless of the actual performance of a utility.[37] Further, to the extent the utility was successful in achieving efficiencies that resulted in cost savings during a PBR plan, the new going-in rates that result from rebasing should reflect these realized savings, thereby benefiting customers throughout the next PBR term.[38] The interveners in this proceeding stated that if such sharing is not done at rebasing, then customers would lose a large portion of benefits of PBR and this form of regulation would be a much less attractive proposition for them.[39]

66. Under the Commission's approach to rebasing, customers should also benefit, in the 2023 COS year, from their respective DFO's achieved efficiency gains during PBR2. The Commission directed the utilities, in their 2023 COS applications, to quantify and clearly demonstrate how the efficiencies realized, and cost reductions achieved, during the PBR2 term are reflected in their forecast revenue requirement and will be passed on to customers.

### 5.1.2 How the utilities quantified the achieved efficiencies

67. The Commission has previously concluded that PBR plans to date have incented the Alberta distribution utilities, including ATCO Gas and Apex, to find efficiencies in service delivery to maximize their profits, similar to what should be experienced in a competitive market.[40] The Commission heard evidence in this proceeding to support this conclusion.

68. ATCO Gas and Apex identified some initiatives that resulted in efficiencies (as further explained in this section), and quantified several efficiencies gained through these initiatives. As set out in Table 7 below, ATCO Gas and Apex both earned more than the approved ROE set by the Commission in the first four years of the PBR2 term based on the data that was available during this proceeding. While both utilities submitted that not all of their achieved ROEs can be attributed to efficiencies (as ROEs may be affected by a multitude of other factors such as changes in the customer consumption of energy, weather and one-time events outside utility control), they acknowledged that achieved ROEs are an indicator of whether or not efficiencies were achieved.[41]

**Table 7. Approved and achieved ROEs for the PBR2 term**

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| | (%) | | | | |
| Approved ROE | 8.5 | 8.5 | 8.5 | 8.5 | 8.5 |
| ATCO Gas | 11.03 | 11.21 | 10.80 | 11.81 | Will be available on May 15, 2023, as part of Rule 005[42] filing |
| Apex | 9.37 | 10.26 | 9.25 | 9.53 | Will be available on May 15, 2023, as part of Rule 005 filing |

69. In its application, ATCO Gas indicated that the two ATCO Distribution Utilities had implemented "hundreds of small improvements to minimize costs across the organization"[43] and expressed its belief "that it would be unlikely that the same level of workforce reductions and

37 Decision 2012-237, paragraph 17.
38 Decision 20414-D01-2016 (Errata), paragraph 26.
39 Transcript, Volume 5, pages 414 and 448 (CCA oral argument).
40 Decision 26356-D01-2021, paragraph 11.
41 Transcript, Volume 2, pages 29-30 (ATCO Gas), and Transcript, Volume 3, page 200 (Apex).
42 Rule 005: *Annual Reporting Requirements of Financial and Operational Results.*
43 Exhibit 26616-X0018, ATCO Gas application, paragraph 192.

organizational transformations would have occurred absent the expanded incentive properties available under the five-year second PBR term plan design."[44] ATCO Gas provided examples of a number programs or initiatives in which efforts were undertaken to improve efficiency during the PBR2 term resulting in reductions to O&M and/or capital costs.[45] Of these, ATCO Gas highlighted its workforce restructuring and organization realignment as being one of the most significant cost-saving initiatives realized during the past two PBR terms. Between 2015 and 2020, ATCO Gas reduced its full-time equivalents (FTEs) by 486, or 26 per cent of its total permanent and temporary FTEs.

70. Apex listed 16 efficiency initiatives that represent its "most impactful and sustainable productivity gains based on the best information available at the time."[46] Apex indicated that the single largest efficiency relates to the implementation of the Automated Meter Reading (AMR) Program, which spanned both the PBR1 and PBR2 terms. AMR produced sustainable O&M cost savings by replacing contract meter readers, who were required to manually read meters through individual site visits, with aerial meter reading.[47] As a result, meter reading costs fell from $1.8 million in 2013 to $387 thousand in 2020.[48]

71. Both utilities explained that the efficiencies they were able to quantify provide good examples of realized productivity gains and capture the most significant cost reductions achieved during the PBR2 term. They indicated, however, that these examples do not represent the entirety of their achieved efficiencies because there are likely other realized cost savings that have not been explicitly quantified. Both utilities contended that tracking, quantifying and analyzing individual productivity gains would require considerable administrative effort and would not be an efficient exercise.[49]

72. In light of these considerations, ATCO Gas offered a high-level calculation of the efficiencies achieved in the PBR2 term. In response to a Commission IR, ATCO Gas submitted that its 2023 COS forecast is $59.2 million lower than the revenue that would have been collected from customers under PBR rates had the PBR2 plan continued in 2023.[50] In ATCO Gas's view, this number demonstrates efficiencies achieved in PBR2. In its rebuttal evidence, ATCO Gas stated that in addition to the notional $59.2 million in cost reductions, its 2023 COS forecast is $16.2 million lower than the revenue under the approved 2022 PBR rates.[51]

73. Apex offered a high-level comparison of its O&M costs per customer reflected in its 2023 forecast relative to the same cost metric going into the PBR1 term, escalated by inflation and customer growth. Based on this analysis, Apex submitted that its 2023 forecast O&M cost is $2.8 million lower than it was immediately prior to the start of PBR1, even after including full recovery of shared corporate services costs as applied for in this proceeding. Normalizing for the

44 Exhibit 26616-X0018, ATCO Gas application, paragraph 255.
45 Exhibit 26616-X0018, ATCO Gas application, Section 8.
46 Exhibit 26616-X0023, Apex application, paragraph 335 including Table 12.2.1-1.
47 Or as Apex explained during the hearing, "… what we do today is we fly airplanes overtop of our service territory and collect our meters." Transcript, Volume 3, page 302, lines 12-14.
48 Exhibit 26616-X0106, AUI-AUC-2022FEB17-001, PDF page 8.
49 Exhibit 26616-X0023, Apex application, paragraph 326; Exhibit 26616-X0018, ATCO Gas application, paragraph 239.
50 Exhibit 26616-X0135, AG-AUC-2022FEB17-001,Table 1, PDF page 9.
51 Exhibit 26616-X0233, ATCO Gas rebuttal evidence, PDF pages 36-37.

Commission's previously ordered disallowance of certain of these costs,[52] the difference increases to $3.9 million. On an O&M per customer basis, this translates to a forecast cost reduction of 5.5 percent assuming full recovery of applied for shared corporate services costs, or an 8.0 per cent cost reduction assuming that the Commission maintains its historical disallowance of certain corporate services costs.[53]

74. Both utilities indicated that, ultimately, all of their achieved efficiencies are, by definition, embedded in actual historical costs which, in turn, form the basis of the 2023 forecast revenue requirement.[54] ATCO Gas and Apex argued that their use of a hybrid methodology in determining their 2023 forecast therefore embedded all efficiencies achieved, both quantified and non-quantified. Specifically, both utilities pointed out that they forecast the majority of their costs using the mechanistic approach based on the escalated 2018-2020 average; therefore, these forecasts reflect actual costs and efficiencies that resulted in cost savings in those years. They also indicated that costs forecast for a program using the non-mechanistic approach also reflect a utility's ability to deliver that program, with all of the efficiencies achieved to date as reflected in the forecasts.

### 5.1.3 Intervener concerns and alternative proposals

75. The interveners were uniformly of the view that the utilities' 2023 forecast revenue requirements do not adequately reflect efficiencies and cost reductions achieved under PBR2. Jan Thygesen for the CCA stated that the applied-for forecasts based on the three-year average reverse the "downtrend" in utility costs that he observed and thus have largely offset the efficiencies gained.[55] Russ Bell for the UCA stated that the "use of a three-year average masks and holds benefits back from customers."[56] Referring to the ATCO Distribution Utilities' IT costs, Calgary stated the 2023 forecast does not properly flow through efficiency gains to customers.

76. The interveners offered the following remedies to address their concerns: (i) the CCA proposed to return to customers an average annual amount of earnings above the approved ROE; (ii) the CCA, supported by Calgary, proposed to include an X factor offset as a third escalation factor (in addition to inflation and customer growth escalators) to account for the efficiencies expected to be achieved in 2023; and (iii) the UCA proposed to use the PBR2 lowest cost year as a basis for 2023 forecasts. Each of these proposals is discussed below.

#### 5.1.3.1 Sharing earnings above the approved ROE

77. On the question of how to set going-in rates for PBR3, J. Thygesen for the CCA proposed to pass through to customers the amount equal to the average earnings in excess of the approved ROE over the PBR2 term, escalated to 2023 dollars using the indexes proposed by the utilities. For ATCO Gas, J. Thygesen calculated this amount to be $28.7 million.

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52 Apex's historical corporate costs disallowances were based on Commission directions pertaining to a different inter-affiliate relationship with a prior parent company, AltaGas Utility Group Inc., in Decision 2012-091, 2010-2012 AltaGas Utilities Inc., General Rate Application – Phase I.

53 Exhibit 26616-X0106, AUI-AUC-2022FEB17-001, PDF pages 6-7.

54 Exhibit 26616-X0023, Apex application, paragraphs 183 and 341; Exhibit 26616-X0018, ATCO Gas application, paragraphs 248-249.

55 Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, paragraph 7.

56 Exhibit 26616-X0203, UCA evidence, PDF page 13.

78. To support their recommendations described above, both Calgary[57] and the UCA[58] pointed to the fact that the utilities earned above the approved ROE during PBR2. However, they did not propose a separate offset to the revenue requirement to account for past earnings above the approved ROE.

79. In argument, the CCA drew parallels with the efficiency carryover mechanism (ECM), a mechanism approved for PBR1 and PBR2 plans that allows the utilities to carry a portion of earnings in excess of the approved ROE from the prior PBR term to the next PBR term. Specifically, the ECM ROE add-on is calculated as 50 per cent of the difference between the average allowed and average actual ROEs over the course of the PBR term, with an upper limit of 0.5 percentage points.[59] The CCA submitted that the approved ECM mechanism implies that efficiencies are defined as "the difference between the average [achieved] ROE over the [PBR] term and the GCOC [approved ROE] rate for the corresponding year."[60] Therefore, the CCA supported the recommendation of J. Thygesen and argued for an offset to the utilities' 2023 forecast revenue requirement equal to the average amount of earnings over the approved ROE, similar to how it is done for the ECM purposes.

80. In its decisions on prior PBR plans, the Commission indicated that the purpose of the ECM is to address the weakening of incentives towards the end of the PBR term "by permitting the utility to continue to benefit from any efficiency gains after the end of the PBR."[61] While the Commission agrees with ATCO Gas's submission that using ECM for the purpose of quantifying achieved efficiencies was not expressly contemplated,[62] the Commission also sees some merit in the CCA's submissions in this proceeding that, for ECM purposes, the difference between the average approved ROE and achieved ROE over the PBR term can be viewed, at least to some extent as a proxy for efficiency gains. In the context of this proceeding, however, the Commission does not accept the CCA's proposal for the reasons that follow.

81. First, as noted earlier in Section 5.1.2, in this proceeding both utilities explained that achieved ROEs are not driven entirely by efficiencies. The Commission notes this is consistent with its own observations in Decision 26356-D01-2021; that is, while it can be a useful indicator, the achieved ROE cannot be fully equated to a measurement of realized efficiencies.[63]

82. Second, the Commission agrees with ATCO Gas's view that the CCA's proposal would effectively constitute an after-the-fact ESM on achieved earnings. An ESM requires careful consideration of many factors and parameters such as symmetry (e.g., whether to share both profits and losses), deadbands within which there is no sharing, and the actual sharing ratio outside of any deadbands. When questioned by the Commission, the CCA accepted the Commission needs to determine whether to share the full amount over the approved ROE or a portion thereof, but did not otherwise address this issue.[64]

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57 Exhibit 26616-X0199, City of Calgary written evidence, PDF page 12.
58 Exhibit 26616-X0203, UCA evidence, PDF pages 11 and 36.
59 Decision 2012-237, paragraph 766 as clarified in Decision 20414-D01-2016 (Errata), paragraph 79.
60 Transcript, Volume 5, page 413 (CCA oral argument).
61 Decision 20414-D01-2016 (Errata), paragraph 73.
62 Transcript, Volume 5, page 579 (ATCO Gas oral reply argument).
63 Decision 26356-D01-2021, paragraphs 25-26.
64 Transcript, Volume 5, page 455 (CCA oral argument).

83. Third, the Commission previously explained that a PBR plan, including all of its elements, must be viewed and considered holistically.[65] The introduction of an ESM to the PBR plan, after all of the elements of PBR2 were established, and without considering the interaction of an ESM with all other elements of the plan, could potentially have a deleterious effect on the utilities' incentives to reduce costs, among other unintended consequences.[66]

84. Finally, introducing an ESM after the fact would undermine the credibility of the regulator, which is crucial to the success of future PBR plans. The CCA proposed what might be described as the retroactive confiscation of earnings above the approved return without addressing detrimental effects of such a confiscation.

85. Unlike the CCA's proposal, the ECM is an approved part of the PBR2 plan. Utilities and consumers knew in advance that the ECM was a component of the current PBR plan. Further the ECM has a cap of 0.5 percentage points. Thus, the concerns expressed above regarding the introduction of an ESM do not apply to the ECM.

#### 5.1.3.2 Using the X factor as an escalation factor

86. The CCA recommended applying the X factor to offset the inflation and customer growth escalation factors proposed by the utilities. In argument, Calgary supported this recommendation.[67]

87. J. Thygesen submitted that the utilities will be able to achieve efficiencies in 2023 because they will be incented to reduce their costs below the approved forecast revenue requirement. J. Thygesen added that this incentive will be further amplified because the utilities may be able to keep the efficiencies realized in 2023 for the duration of the next PBR term. Further, J. Thygesen noted that the utilities will still be under PBR incentives in 2021 and 2022, therefore, costs forecast under the mechanistic approach need to take those incentives into account.[68]

88. The utilities did not agree with this proposal. ATCO Gas pointed out that capital-related efficiencies achieved in 2021 and 2022 will be reflected in the 2023 opening rate base, which will be trued up to reflect the actual costs. Both ATCO Gas and Apex indicated that the 2023 test year is not within any PBR term and, therefore, it is inappropriate to employ an X factor in developing the 2023 forecasts. They further stated that using an X factor offset does not align with the purpose of the current COS rebasing to realign the utilities' revenues and costs. ATCO Gas emphasized that the purpose of this proceeding was to reflect in its 2023 forecast any efficiency gains and cost savings actually realized and not future efficiencies anticipated, or projected, to be achieved in 2023.[69]

89. The Commission agrees with the explanations provided by the utilities and, therefore, rejects the CCA's proposal to use an X factor to offset the inflation and customer growth escalation factors employed in the utilities' mechanistic approaches to forecasting 2023 costs.

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[65] Decision 20414-D01-2016 (Errata), paragraph 25.
[66] Exhibit 26616-X0231, Apex rebuttal evidence, paragraph 63, and Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraph 92.
[67] Transcript, Volume 5, pages 509-510 (Calgary oral argument).
[68] Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, PDF page 35, paragraph 104.
[69] Transcript, Volume 2, page 40; Transcript, Volume 3, page 119.

To the extent the utilities are able to reduce their actual costs below the Commission-approved forecast, customers will benefit from these savings at the time of the next rebasing.

#### 5.1.3.3 Using lowest cost year as a basis for 2023 forecasts

90. In his evidence for the UCA, R. Bell expressed the view that in setting the going-in rates for a PBR term, "the use of the lowest O&M cost year best reflects the incentives of PBR and should ensure that all benefits of PBR are passed along to customers."[70] R. Bell, therefore, recommended that the lowest cost year in PBR2 should be used as the basis for forecasting 2023 O&M costs for ATCO Gas and Apex.

91. As further discussed in Section 8.6, Calgary proposed to include efficiency factors to offset the ATCO Distribution Utilities' IT costs and these efficiency factors were based, in part, on lowest year O&M and capital costs. Both Calgary[71] and the CCA[72] indicated they could accept the lowest O&M cost rebasing approach as an alternative to their proposals, as the former approach was compatible with the reasoning behind the preferred recommendations of Calgary and the CCA.

92. As pointed out by R. Bell, the Commission adopted the lowest O&M cost approach in the rebasing process for the PBR2 term.[73] However, any proposed use of the lowest cost year method in the present rebasing proceeding requires careful consideration. On the one hand, the Commission agrees with the views of the utilities that a wholesale adoption of the lowest O&M cost year as an alternative rebasing methodology is not consistent with the general direction of Decision 26354-D01-2021. On the other hand, the Commission agrees with the interveners that Decision 26354-D01-2021 allowed for the consideration of a more mechanistic, high-level approach to quantify the efficiencies achieved during the PBR term 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.[74] The Commission recognized the value of comparing the 2023 forecast costs to the lowest cost year when it requested that the utilities provide this information as part of their rebasing applications.[75]

93. All parties in this proceeding agreed that the efficiencies achieved and savings gained in the PBR2 term will ultimately be reflected in the utilities' actual costs. Therefore, basing the utilities' 2023 forecasts on actual experienced costs is an effective way to ensure that efficiencies are passed on to customers. While R. Bell advocated for the lowest cost year, the utilities used the three-year average of actual costs. For the reasons that follow, and for the purposes of this decision, the Commission accepts the use by ATCO Gas and Apex of a 2018-2020 average of historical actual costs incurred during the PBR2 term and finds that this average reflects efficiencies achieved during that period.

94. First, the actual 2018-2020 costs were incurred in the first three years of the PBR2 plan when the incentive properties of the plan were strongest. These years do not contain the

70 Exhibit 26616-X0203, UCA evidence, PDF page 10.
71 Transcript, Volume 5, page 509 (Calgary oral argument).
72 Transcript, Volume 5, page 448 (CCA oral argument).
73 Decision 20414-D01-2016 (Errata), paragraph 52.
74 Decision 26354-D01-2021, paragraph 41.
75 Decision 26354-D01-2021, paragraphs 21 and 31.

undesirable incentive for utilities to increase costs towards the end of the PBR term in anticipation of rebasing.

95. Second, the use of a three-year average reasonably aligns with the overall objective of the present COS rebasing to realign costs with revenues, as explained in Section 4. A three-year average attenuates the effect of any major fluctuations both within and outside the utilities' control (e.g., weather, the COVID-19 pandemic) that may occur in a given year. In contrast, using a single (lowest cost) year may require the Commission to consider whether any adjustments to that year's costs are required to account for any anomalous events that may have occurred in that year.[76] In the PBR2 rebasing proceeding this necessitated an assessment of such events at considerable cost in terms of time and effort for all concerned. In his evidence, R. Bell acknowledged that a three-year average may be appropriate in the circumstances where there are recurring costs that do not occur annually such as the impacts of a severe weather event.[77]

96. Finally, as R. Bell's recommendation concerned O&M costs only, it is not clear to the Commission how his proposal accounted for any capital-related efficiencies achieved during PBR2. For example, the CCA pointed to the need to separately account for capital-related savings achieved in PBR2 under the operation of the K-bar capital funding mechanism.[78]

97. Having determined that using the 2018-2020 average of historical costs is an effective way to ensure that efficiencies are passed on to customers, the Commission also reviewed ATCO Gas's and Apex's use of escalators. As explained in Section 3, under a mechanistic approach, the 2023 costs are forecast by escalating the average of actual 2018-2020 costs by the utilities' chosen escalation factors. The same escalated 2018-2020 average costs were also used by each of ATCO Gas and Apex to quantify their achieved efficiencies for costs forecast under a non-mechanistic approach and to justify the general reasonableness of those forecasts. Parties in this proceeding pointed out that, for this reason, the indexes used for escalating the 2018-2020 average play an important role in quantifying the achieved efficiencies and passing them on to customers. As further set out in Section 5.2 of this decision, the Commission agrees and directs certain changes to the proposed escalators. Overall, for costs forecast using a mechanistic approach, the Commission is satisfied that the use of the 2018-2020 average, escalated by indexes approved in Section 5.2, results in a 2023 forecast that is reasonably reflective of the efficiencies achieved during the PBR2 term.

98. For costs forecast using a non-mechanistic approach, the Commission compared the 2023 forecasts to the escalated 2018-2020 average. Both ATCO Gas and Apex undertook a similar analysis in their applications. The Commission also relied on efficiencies reported by the utility for a particular program, where applicable.

### 5.1.4 Measuring efficiencies in PBR3

99. During the oral hearing, the Commission questioned ATCO Gas and Apex on how they measure productivity and, more importantly, how they measure changes in the productivity of their business over time. Related to this was a discussion on potential measures of output for a gas distribution utility. The record of this proceeding suggests that ATCO Gas and Apex were

[76] Exhibit 26616-X0231, Apex rebuttal evidence, paragraph 11, and Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraph 324.
[77] Exhibit 26616-X0203, UCA evidence, PDF page 12.
[78] Transcript, Volume 5, page 449 (CCA oral argument).

reluctant to rely on any such measures for the purposes of quantifying efficiencies. As well, the debate on the most appropriate measure of output for a gas distribution utility appears to be unsettled, and will require additional work going forward.[79]

100. The evidence of both utilities was that they do not systematically track efficiencies gained for individual projects or programs in real time. In fact, both utilities suggested it was impractical, inefficient and not cost effective to track whether specific programs actually achieved the efficiencies intended. Apex noted it would rather "spend very much more of our energy focussed on managing the costs."[80]

101. Ultimately, both ATCO Gas and Apex admitted that, to the extent they were able to quantify efficiencies on a program basis, even for major programs or projects, it was largely done only once it became clear that the Commission would require some quantification of efficiencies over the PBR term. The Commission is aware, however, that the utilities prepare business cases for major projects and programs and that often the very rationale for the initiatives underlying the business cases relate to efficiency gains and cost savings projected to be realized by implementing a new process or technology. The Commission therefore finds it not to be credible for the utilities to suggest that they are unable to assess potential efficiency gains at the project approval stage and subsequently track whether these efficiencies were realized.

102. However, what is clear from the record of this proceeding is that neither ATCO Gas nor Apex has a documented process to which it could point in evidence, for tracking whether the projected efficiencies or cost savings associated with a particular initiative were indeed realized. The Commission is not inclined, at this time, to require the utilities to begin tracking all individual initiatives and programs that may result in efficiencies and the associated cost savings. The Commission does, however, expect that quite apart from the regulatory process and the very fundamentals of a PBR regime, which are based on the ability of utilities to achieve efficiency gains over time, the utilities can and should be tracking and measuring whether the programs and large-scale initiatives that they implement are achieving the intended goals, including efficiency gains and related cost savings.

103. To avoid similar challenges in identifying the achieved efficiencies and calculating the realized savings at the next rebasing, the Commission directs ATCO Gas and Apex to present proposals in Proceeding 27388 where the parameters for PBR3 plans will be set, on how efficiencies can be effectively quantified and tracked over time. ATCO Gas provided examples of some possible forward-looking productivity and/or efficiency measures, including: (i) O&M per customer; (ii) O&M per kilometre (km) of line; and (iii) O&M per GJ delivered. ATCO Gas emphasized the importance of service quality measures.[81] Apex agreed that the three measures identified by ATCO Gas are possible candidates.[82]

## 5.2 Escalation factors

104. ATCO Gas and Apex used escalation factors in two ways. First, escalation factors were used to simplify variance explanations for 2023 costs forecast under the non-mechanistic approach. Both utilities generally adjusted their historical actual costs by inflation (including

79 Transcript, Volume 3, pages 160-167.
80 Transcript, Volume 3, page 289.
81 Transcript, Volume 2, page 32.
82 Transcript, Volume 3, pages 201-203.

labour costs) and customer growth and compared their 2023 forecasts to the escalated historical numbers. Second, for cost categories forecast under the mechanistic approach, the utilities used their chosen escalation factors to adjust the 2018-2020 historical average actual costs to arrive at their 2023 forecast. Although the Commission relied on historical cost comparisons and variance explanations in assessing the bottom-up forecasts, in this section the Commission focuses on the escalation factors used in developing the mechanistic forecasts.

105. The reasonableness of 2023 revenue requirement forecasts contained in the rebasing applications depends, in large part, on the reasonableness of the escalation factors used by each of the utilities. The Commission has therefore reviewed the escalation factors used by both utilities as the basis for their 2023 forecasts. Although ATCO Gas and Apex took similar approaches in applying their chosen escalation indexes, their escalation factors differ in several ways. Accordingly, in this section, the Commission reviews the escalation indexes adopted by ATCO Gas and Apex and how they differ from each other. The Commission then makes findings on the adoption of escalation factors, how they relate to quantifying efficiencies, and the implications for each utility's 2023 forecast costs.

### 5.2.1 The escalation factors used by ATCO Gas and Apex

106. ATCO Gas used the same escalation factors for O&M and capital expenditures: one for inflation and one for customer growth. Apex used a similar approach. Table 8 below summarizes the escalation factors used by the two utilities.

**Table 8. Escalation factors used by ATCO Gas and Apex**

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| | (%) | | | | |
| **ATCO Gas**[83] | | | | | |
| Inflation (O&M and capital) | 1.58 | 2.27 | 1.75 | 2.47 | 2.50 |
| Customer growth | 1.39 | 1.42 | 1.16 | 1.23 | 1.25 |
| **Apex**[84] | | | | | |
| Inflation (O&M and capital) | 1.58 | 2.27 | 1.44 | 3.00 | 2.78 |
| Customer growth | 0.85 | 1.00 | 0.40 | 0.90 | 1.20 |

Note: The table reflects the updated 2021-2023 CPI values.

107. Both utilities justified their choice of escalators by explaining that the inflation escalator accounts for the changes in prices of materials and labour, while the customer growth escalator accounts for changes in the size of the distribution system. Thus, they indicated that both escalators are needed to adjust (i.e., normalize) the dollar quantum of costs to facilitate a meaningful (i.e., apples-to-apples) comparison of costs year-over-year. The Commission will address each of these escalation factors in turn.

### 5.2.2 Inflation escalator

108. The 2014-2020 inflation rates for ATCO Gas and Apex were derived using the same indexes used for calculating the I factor during the PBR1 and PBR2 terms, namely, the annual average value for the all-items Alberta Consumer Price Index (CPI) and the average value for

83 Exhibit 26616-X0018, ATCO Gas application, Table 5, PDF page 21 for 2019-2020 values; Exhibit 26616-X0192, ATCO Gas application update, Table 13, PDF page 23 for 2021-2023 values.
84 Exhibit 26616-X0023, Apex application, PDF page 16, Table 7 for 2019-2020 values; Exhibit 26616-X0195, Apex preliminary full-year 2021 actuals and update, PDF pages 16-17, paragraph 38 for 2021-2023 values.

Alberta weekly earnings (AWE), weighted at 45 per cent and 55 per cent, respectively. However, ATCO Gas and Apex calculated the inflation escalator on a calendar-year basis, rather than the July-to-June basis as is used for the I factor.[85] [86]

109. For the 2021-2023 CPI amounts, ATCO Gas relied on forecasts published by well-known third parties (later updated to reflect the 2021 actual CPI).[87] For the 2021-2023 labour amounts, ATCO Gas used the weighted average forecast salary escalation for its union and non-union employees. This is discussed in greater detail in Section 5.2.6.[88] Table 9 summarizes ATCO Gas's inflation escalator calculations.

**Table 9. Calculation of ATCO Gas's inflation escalator**

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| Alberta CPI (Note 1) | 1.73 | 1.11 | 3.15 | 4.03 | 2.59 |
| Labour cost escalator | 1.46 (AWE) | 3.21 (AWE) | 0.60 (70/30 union/non-union weighted) | 1.20 (70/30 union/non-union weighted) | 2.43 (70/30 union/non-union weighted) |
| **45/55 CPI/Labour weighted** | **1.58** | **2.27** | **1.75** | **2.47** | **2.50** |

Note 1: The table reflects the updated 2021-2023 CPI values.

110. For the 2021-2023 CPI amounts, Apex relied on forecasts published by seven independent, well-known sources.[89] For the 2021-2023 labour amounts, Apex relied on its negotiated union agreements for union employees and a report prepared for Apex by Mercer for non-union employees. Table 10 summarizes Apex's inflation escalator calculations.

**Table 10. Calculation of Apex's inflation escalator**

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| Alberta CPI (Note 1) | 1.73 | 1.11 | 3.2 | 4.1 | 2.5 |
| Labour cost escalator | 1.46 (AWE) | 3.21 (AWE) | 0.0 (52/48 union/non-union weighted) | 2.1 (52/48 union/non-union weighted) | 3.0 (52/48union/non-union weighted) |
| **45/55 CPI/Labour weighted** | **1.58** | **2.27** | **1.44** | **3.00** | **2.78** |

Note 1: The table reflects the updated 2021-2023 CPI values.

111. Subject to the modifications directed below, the Commission considers the approaches taken by both ATCO Gas and Apex to estimate the effects of inflation to be reasonable. The Commission finds it acceptable to escalate historical costs by some measure of inflation because of the widely accepted economic concept of the time value of money. The prices for all goods and services change over time. The Bank of Canada uses monetary policy to target economy-wide inflation to be between one and three per cent annually. CPI is widely used to measure inflation and restating nominal dollars into real, constant dollars by adjusting the nominal dollars by CPI is also widely accepted. The combination of indexes measuring the increases in the price

85 Exhibit 26616-X0018, ATCO Gas application, paragraph 52.
86 Exhibit 26616-X0023, Apex application, PDF pages 19-20, paragraph 48.
87 Exhibit 26616-X0018, ATCO Gas application, Table 6, updated in Exhibit 26616-X0192.
88 In the applications, members of the Natural Gas Employee Association are designated as "association" or "in-scope" employees, whereas non-unionized members are designated as "out of scope" employees.
89 Exhibit 26616-X0023, Apex application, PDF page 17, paragraph 38 for 2019-2020 values; Exhibit 26616-X0195, Apex preliminary full-year 2021 actuals and update, PDF pages 14-15, paragraphs 33-34 for 2021-2023 values.

of labour (represented by Alberta AWE) and non-labour (represented by Alberta CPI) inputs, weighted at 45 and 55 per cent, respectively, has been accepted by the Commission in the past as a useful proxy for the inflationary effects that utilities experience.[90] The interveners generally agreed with using some measure of inflation to adjust historical actual costs.[91]

112. Both ATCO Gas and Apex relied on the same weightings between CPI and labour costs currently established for the I factor. Both used data from well-known sources for their historical and forecast CPI. The Commission also accepts, for the purposes of this decision, the calculation of CPI and labour escalators on a calendar year basis (rather than a July to June basis as is currently done for the I factor calculation). Doing so aligns more closely with the utilities' costs and revenues, which are measured on a calendar year basis. Given the Commission's approval to use the most up-to-date data,[92] the Commission directs ATCO Gas and Apex to use the 2021-2023 CPI values as shown in tables 9 and 10 above in their respective compliance filings. The Commission denies ATCO Gas's request to further update its forecasts at the time of the compliance filing.

113. Regarding labour costs, both ATCO Gas and Apex used the Alberta AWE index as a substitute for their labour costs escalator for 2019 and 2020, and used their own actual or projected labour cost increases for 2021-2023. In the Commission's view, it is more methodologically sound to use the utility's own actual or forecast labour cost growth for the entire 2019-2023 period so that the data for both historical and forecast costs is consistent. The Commission considers the use of the utilities' actual and forecast labour costs is reasonable for purposes of the inflation escalator because the objective of this proceeding is to realign each of the utility's costs with revenues. Further, in Section 5.2.6 of this decision, the Commission reviews the 2021-2023 proposed labour cost escalators developed by the utilities, and finds them to be reasonable. As such, the Commission directs ATCO Gas and Apex to recalculate their 2019-2020 inflation indexes based on their own labour cost data using the same methodology used for developing their 2021-2023 labour cost indexes as shown, respectively, in tables 9 and 10 above.

114. The Commission notes that its acceptance of ATCO Gas's and Apex's inflation escalation factors (with the modifications directed in this section) applies to this proceeding only. What constitutes an appropriate I factor for purposes of PBR3 will be determined by the Commission panel presiding over Proceeding 27388 based on the evidentiary record of that proceeding.

### 5.2.3 Customer growth escalator

115. Both ATCO Gas and Apex calculated their customer additions growth escalators as the year-over-year change in their average customer count.[93] The actual year over year change was

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90 Decision 2012-237, paragraph 228.

91 Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, paragraph 99; Exhibit 26616-X0227, UCA-AUC-2022APR19-002(e); Exhibit 26616-X0312, General oral argument of the City of Calgary, paragraph 4.

92 Exhibit 26616-X0191, AUC letter – Clarification on April 1 filing and ATCO Electric request to change process and schedule, paragraph 10.

93 Exhibit 26616-X0018, ATCO Gas application, paragraph 64, Exhibit 26616-X0023, Apex application, paragraph 46.

calculated using the average customer count reported in annual Rule 005 filings, and forecast values were used for 2021-2023. These escalators are shown in Table 8 above.

116. The Commission must decide whether it is reasonable to use a customer growth escalator to forecast the utilities’ 2023 costs and, if so, what that escalator should be and where it should be applied. In the sections that follow, the Commission considers first whether applying a customer growth escalator is reasonable and what customer growth escalator should be used.

### 5.2.4 Whether applying a customer growth escalator is reasonable

117. For the reasons that follow, the Commission has determined that it is reasonable for ATCO Gas and Apex to use a customer growth escalator to forecast their respective 2023 costs.

118. Interveners expressed concern with the use of a customer growth escalator. J. Thygesen, on behalf of the CCA, pointed out that there is not a one-to-one relationship between customer growth and utility costs meaning that a one per cent increase in the number of customers would not necessarily result in a one per cent increase in utility costs.[94] J. Thygesen also stated that there is no conceptual basis to escalate historical cost by customer growth.[95] Calgary argued that using customer growth to escalate historical costs means that successive years of earnings above the allowed return will not be passed along to customers.[96] To the extent that these assertions are valid, they imply that the utilities’ use of their preferred escalation factors overstates the resulting 2023 cost forecast.

119. ATCO Gas and Apex responded to these intervener submissions by pointing to a footnote in Decision 26354-D01-2021 that mentions customer growth as a potential escalator,[97] to support their reliance on their preferred customer growth escalation factor. However, the Commission considers this footnote does not remove ATCO Gas’s or Apex’s burden to demonstrate that their forecasts are reasonable, nor does it negate the Commission’s role in adjudicating any proposed inflation or customer additions growth escalator.

120. The Commission sees merit in adjusting historical costs to account for growth of the utilities’ distribution systems over time. ATCO Gas indicated that it added 34,000 customers between 2018 and 2020 and expected that it would have 74,000 more customers in 2023 compared to 2018.[98] Apex increased its average customers by 1,484 between 2018 and 2020[99] (increase of 1.9 percent) and by 2023 forecast to have 3,490 more customers (a 4.4 percent increase) compared to 2018. In the Commission’s view, the total costs associated with providing gas distribution service in 2023 can reasonably be assumed to be higher than costs for the system in 2018, when ATCO Gas had 74,000 fewer customers and Apex had 3,490 fewer customers.

121. The Commission is also persuaded that a volume adjustment is required to compare years on a consistent basis. ATCO Gas explained that using a customer growth escalator allowed it to forecast what it would have cost in each historical year to operate the size of distribution system expected in 2023.[100] It stated that it expressly used the growth escalator on the 2018 and 2019

94 Exhibit 26616-X0205.3, CCA evidence of J. Thygesen, PDF pages 8-12, Section 2.2.
95 Exhibit 26616-X0205.3, CCA evidence of J. Thygesen, PDF pages 14-15, Section 2.4.
96 Exhibit 26616-X0312, City of Calgary oral argument, paragraph 16.
97 Decision 26354-D01-2021, footnote 3.
98 Transcript, Volume 3, pages 111-112.
99 Exhibit 26616-X0024, Appendix 6, line 18.
100 Exhibit 26616-X0233, ATCO Gas rebuttal, paragraph 32.

values to determine a comparable dollar of revenue requirement that would have been required to operate a distribution system the size of ATCO Gas's in 2020 since 2020 is the base year used for the 2023 forecast. It added that, absent such an adjustment to reflect that the system had grown over 2018-2020, the resulting three-year average would have understated the costs of owning and operating the system which existed in 2020 over the three-year period in question. ATCO Gas stated that by not using the growth escalator to restate 2018 and 2019 nominal costs, the forecast would reflect the cost to operate and maintain the average system during the 2018-2020 period, not the size of the system that existed in 2020; and not the system that is expected to be in place in 2023.[101] Apex explained that the concept of a growth escalator is similar to normalizing for inflation over multiple years in that it compares what costs would have been in each year had the number of customers been the same.[102] The Commission agrees with ATCO Gas and Apex that using a customer growth escalator in this way (to normalize volumes) is similar in concept to the inflation escalator, which allows for a year-over-year comparison of prices in constant dollars

### 5.2.5 What customer growth escalator should be used

122. Having decided that using a customer growth escalator is reasonable, the Commission must now decide whether the specific customer growth escalators used by ATCO Gas and Apex are reasonable.

123. Both ATCO Gas and Apex proposed customer growth escalators based on the actual or forecast year-over-year change in the average customer count on their respective distribution systems. If, for example, ATCO Gas or Apex experienced a 1.5 per cent change in the average number of customers in a given year, then its customer growth escalator would be 1.5 per cent.

124. For the reasons that follow, the Commission finds that there is not a one-to-one relationship between customer growth and utility costs, and that the chosen customer growth escalators of ATCO Gas and Apex are likely to overstate each utility's costs as they imply that there are no economies of scale. The underlying assumption of the utilities' proposed customer growth escalators is that customer growth reasonably approximates the change in the size and the associated costs of their systems.[103] However, the record of this proceeding does not support that assumption.

125. In particular, no party presented evidence that established the existence of a one-to-one relationship between customer growth and the utilities' O&M and capital costs. Indeed, such evidence as there was tended to show a less than perfect correspondence between customer growth and changes in costs. For example, during the hearing, ATCO Gas and Apex acknowledged that while the total number of customers they serve has increased over time, their O&M and capital costs have not grown in lockstep.[104] Additionally, the record shows that, for each of these utilities, changes in actual costs in several of their O&M and capital categories are (and have been) driven by many factors of which customer growth is just one.[105] For its part, ATCO Gas accepted that the customer growth escalator is not a perfect "mechanism." It appeared to maintain, however, that the absence of a strict correspondence between cause (i.e.,

101 Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 40-43.
102 Exhibit 26616-X0231, Apex rebuttal evidence, paragraph 40.
103 Transcript, Volume 2, pages 47-48; Transcript, Volume 4, page 373.
104 Transcript, Volume 2, pages 50-52; Transcript, Volume 3, page 253.
105 Transcript, Volume 2, pages 50-52; Transcript, Volume 4, page 376.

customer growth) and effect (proportionately higher costs) was likely only a short-term phenomenon, during which customer growth can lead to some costs being higher, and some being lower.[106] The Commission finds insufficient evidence on the record of this proceeding to support the existence of a one-to-one correspondence between customer growth and utility costs in either the short-run or long-run.

126. In the Commission's view, incorporating customer growth on a one-for-one basis in mechanistic forecasts implies that utilities do not benefit from economies of scale, a proposition inconsistent with conventional economic theory and more than a century of economic regulation of public utilities. As a regulated utility with the economic attributes of a natural monopoly grows and serves more customers over time, its average cost per unit of output would be expected to fall, even as its total costs are rising. This follows directly from the textbook model of natural monopoly. When questioned about this during the hearing, neither ATCO Gas nor Apex denied that their operations exhibit economies of scale.[107]

127. That being said, the evidence in this proceeding is that the utilities do not systematically measure their unit costs or changes in their unit costs over time or that they were reluctant to rely on these metrics to identify or track achieved efficiency gains over time. As a result, the record of this proceeding provides no indication of the magnitude of economies of scale possessed by ATCO Gas or Apex.

128. As stated at the outset of this section, the reasonableness of 2023 revenue requirement forecasts contained in the rebasing applications depends in large part on the reasonableness of the escalation factors used by each of the utilities. Therefore, it is of critical importance that the Commission have confidence in the escalation factors used. While the Commission agrees that customer growth will drive higher costs in the long term, the Commission finds that the relationship between customer growth and associated costs is not one-to-one and, therefore, that a downward adjustment to the customer growth escalators proposed by ATCO Gas and Apex is required.

129. As a result, the Commission has determined that it is necessary to introduce an offset to the customer growth escalation factors used by both utilities to account for its findings that (i) there is not an observed one-to-one relationship between customer growth and utility costs; and (ii) there exist economies of scale that are not accounted for in the application of the customer growth escalator. Having reviewed the record and exercised its judgment, the Commission directs each of the utilities to reduce their proposed customer growth escalation factors by 15 per cent.[108]

130. ATCO Gas[109] and Apex[110] submitted that, while not a perfect proxy, the customer growth escalation factor, allows for a reasonable approximation of utility costs while avoiding the added expenditure in time and resources associated with a line-by-line COS review of every forecast cost. The Commission agrees, subject to the following. The customer growth escalation factor, as adjusted by the Commission in this decision, strikes a reasonable balance among the following

106 Transcript, Volume 2, pages 45-48.
107 Transcript, Volume 3, pages 157, 160 and 286-287.
108 That is, when converting historical costs into 2023 dollars, the utilities will use a formula (1+Inflation)x(1+Customer Growth*0.85).
109 Transcript, Volume 2, page 45.
110 Transcript, Volume 4, page 374.

objectives: (i) achieving the requisite level of precision in determining the 2023 revenue requirement; (ii) reducing regulatory burden as part of a streamlined review process; and (iii) ensuring that efficiencies achieved during the PBR2 term are passed on to customers.

131. In Section 5.1 of this decision, the Commission indicated that the development of measures of productivity change and distribution utility output over time will be considered in the PBR3 Proceeding 27388. In the Commission's view, this exercise will also aid in developing a more robust escalator to account for the growth of the utility systems and associated costs and will allow for both year-over-year and long-term comparisons on a consistent basis.

### 5.2.6 Forecast labour escalations for ATCO Gas and Apex

132. As shown in Table 9, ATCO Gas applied for a total labour escalator of 2.43 per cent in 2023, consisting of a four per cent salary increase for its non-union[111] employees, and 1.75 per cent increase for its union employees, weighted at 30 and 70 per cent, respectively. As shown in Table 10, Apex applied for a three per cent increase for both union and non-union employees for 2023. ATCO Gas and Apex each engaged Mercer (Canada) Limited to provide evidence to support their non-union salary escalation requests.[112] Apex's union escalation for 2023 is also based on the Mercer recommendation as its collective agreement with union employees expires on December 31, 2022.[113]

133. Mercer's median salary increase expectations for ATCO Gas's non-union peer group were 2.7 per cent and 2.5-3.0 per cent for 2022 and 2023, respectively.[114] ATCO Gas explained its proposed escalation of four percent recognizes that ATCO Gas is presently positioned 17 per cent below market on target total remuneration, and eight percent below market on target cash compensation.[115], and that the proposed escalation would position them 14.45 per cent below market on target total remuneration and five percent below market on target cash compensation.[116] ATCO Gas stated that its objective in managing non-union labour costs is to be at the mid-point of the market, i.e., the 50th percentile. ATCO Gas stated it will continue to monitor the market and respond accordingly to ensure it is able to attract and retain experienced employees, particularly given the current economic environment in which competition for skilled labour among employers has intensified.[117] ATCO Gas stated that the recommended salary escalation factor of four percent for both 2022 and 2023 reflects the current economic climate in Alberta, since the economy is expected to experience higher GDP growth and significant inflationary pressures over the next several years, resulting in upward pressure on salaries and wages.[118]

134. Apex explained it chose the upper end of the 2.5 per cent to 3.0 per cent range recommended by Mercer as the basis for its 2023 forecast increase for non-union employees. It said that it did so because, at the time of its application, the Government of Alberta 2021-2022 Mid-Year Update issued in November 2021 used forecast assumptions for the AWE of 2.2 per

111 Out-of-scope employees refers to non-union employees, while in-scope refers to employees belonging to the union.
112 Exhibit 26616-X0023, Apex application, PDF page 18, paragraph 43-44.
113 Exhibit 26616-X0023, Apex application, PDF pages 17-18, paragraphs 41-44.
114 Exhibit 26616-X0135, AG-AUC-2022FEB17-002(d), PDF page 13.
115 Exhibit 26616-X0135, AG-AUC-2022FEB17-002(d).
116 Exhibit 26616-X0135, AG-AUC-2022FEB17-002(e).
117 Exhibit 26616-X0018, ATCO Gas application, paragraph 60.
118 Exhibit 26616-X0135, AG-AUC-2022FEB17-002(d).

cent in 2022 and 3.3 per cent in 2023. Subsequently, in February 2022, the Government of Alberta released its 2022 budget in the 2022-2025 fiscal plan and updated its AWE forecast to 3.4 per cent in 2022 and 3.8 per cent in 2023 which, as stated in the Government of Alberta update, reflects a tightening labour market resulting in upward pressure on wages to compete for and attract workers. As a result, Apex submitted that 3.0 per cent is a conservative salary increase to retain and attract employees.[119]

135. The CCA opposed the applied-for non-union salary increases of ATCO Gas and Apex. The CCA contended that ATCO Gas and Apex are forecasting substantially higher increases for 2022 and 2023 than are reasonable and noted that:

(a) The ATCO Gas increase of four per cent in 2022 is 33 per cent higher than any of the comparator groups determined by Mercer, and reverses the trend under PBR in which non-union increases were lower than union increases on average (1.77 per cent versus 2.89 per cent).[120]

(b) ATCO Gas's position relative to the median has no bearing on what the percentage increase should be. Under PBR, ATCO Gas determined that, in some cases, allowing the levels to slip relative to benchmarks was reasonable while still being able to provide utility service. The utilities found it acceptable under PBR incentives to operate below the market median, and the COS proceeding should not over-rule that judgment and those determinations by the utilities. The CCA noted that ATCO Gas shareholders had record or near record profits during the years in which non-union increases were lower, and therefore had more than sufficient funds to pay out the equivalent in union increases. This, in turn, led the CCA to suggest that ATCO Gas apparently decided it would favour shareholders over non-union employees, and to behave as if what is good enough for shareholders is good enough for customers. The CCA stated that the increase for non-union employees should be limited to the union increase, and that the Commission need not be concerned with ATCO Gas's ability to recruit, or with turnover and employee satisfaction since it is clear these were considered by ATCO Gas over the PBR period when it kept the non-union increases lower than union increases.

(c) The proposed four per cent increase for ATCO Gas is more than double the average of 2023 All Alberta Union Settlements[121] (1.87 per cent for 2023). The CCA noted that while ATCO Gas may argue that union settlements are not relevant to increases for non-union employees, Apex is forecasting the same increase for union and non-union employees and there have been, on average, minimal differences between salary escalations for union and non-union employees[122] for Apex since 2013.

(d) The firms included in the All Alberta Union data are preferable to the Mercer data as the former includes more companies, is updated monthly, is independent, is based on actual settlements, is forward looking, and represents the job market that the utilities recruit from. As such, the CCA was agreeable to using the latest number

119 Exhibit 26626-X0106, AUI-AUC-2022FEB17-003(a), PDF pages 17-19.
120 Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, paragraphs 54-55.
121 All Alberta Union settlements refer to Wage Settlements in Alberta for all industries.
122 Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, paragraph 59.

of All Alberta Union Settlements at the time of this decision or the latest number available at the time of the compliance filing to this decision.[123]

(e) Since the utilities provide budgets that presumably reflect their estimate of what they can convince the Commission to approve, the Commission has an indirect effect on the forecasts of the regulated utilities. The CCA submitted that this sets up a circular reasoning chain where the peer groups include the same utilities regulated by the Commission, and that having all Alberta PBR utilities entering a COS year forecasting high settlements boot-straps increased rates by using other utilities in similar proceedings to justify increases. The CCA added that there is no reason to believe that Mercer does not provide similar services to many of the non-utility companies in the comparator group that, in turn, creates a feedback loop in which Alberta utilities are cited to support the non-utility recommendations.[124]

(f) Utilities have provided no evidence of higher rates of attrition, turnover or other measures that indicate there is an issue.[125]

136. The UCA also considered the applied-for increases problematic and stated that:

(a) Mercer found that ATCO Gas was 17 per cent below market, yet ATCO Gas stated it relies on information annually to ensure base salary stays aligned with peers. Additionally, there were several years where ATCO Gas had no salary increase, and only a 0.5 per cent increase in 2015. If ATCO Gas is awarding annual increases that align with its peers, it seems impossible that ATCO Gas would now be paying 17 per cent below market.[126] As a result, any increase in non-union salary should be limited to forecast CPI.

(b) If ATCO Gas implements the increases on April 1, 2022, and the revenue requirement incorporates the annual increase effective January 1, 2022, this will overcompensate ATCO Gas for the salary increase. Only three-quarters of the allowed percentage increase should be incorporated in 2022 and 2023.[127]

137. The Commission approves ATCO Gas's increase of 1.75 per cent for union employees for 2023 as negotiated in a three-year collective agreement that expires on December 31, 2023.[128] In the context of the current economic circumstances facing utilities in Alberta, including inflationary pressures resulting in higher salary expectations, the proposed salary escalation is reasonable; for example, as ATCO Gas pointed out, the Government of Alberta included in its 2022-2025 Fiscal Plan AWE assumptions of 3.4 per cent for 2022 and 3.8 per cent for 2023.[129]

[123] Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, paragraphs 68-74.
[124] Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, paragraphs 75-80.
[125] Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, paragraph 93.
[126] Exhibit 26616-X0203, UCA evidence, PDF page 26.
[127] Exhibit 26616-X0203, UCA evidence, PDF page 27.
[128] Exhibit 26616-X0018, ATCO Gas application, paragraph 57.
[129] Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 16-18.

138. The Commission also finds the salary escalations proposed for non-union employees by ATCO Gas, and for both union and non-union employees by Apex, to be reasonable and approves them, as filed for the reasons that follow.

139. The Commission has reviewed the non-union market positioning estimates put forth by Mercer, and is mindful of the limitations of Mercer's analysis.[130] It was the evidence of ATCO Gas that its target total remuneration levels are 17 per cent lower than median levels for ATCO Gas's peer group. The UCA emphasized that if ATCO Gas annually ensures that its base salary continues to align with its peers, current levels should not be 17 per cent below market. The Commission not only agrees with this proposition, but finds that ATCO Gas's shareholders have benefited as a result of ATCO Gas compensating its non-union employees below Mercer's peer group medians for each employee category during the current PBR term. The fact that ATCO Gas is now 17 per cent below median market levels, by virtue of decisions entirely within its discretion to make, is not, in itself, a compelling reason to approve the requested increase in employee compensation on the very eve of the next PBR term. Due to the magnitude of this avoidable disparity, the Commission considered disallowing some portion of the proposed wage escalation. However, the Commission accepts, and puts considerable weight on, the submission by ATCO Gas that its weighted labour escalators of 1.20 per cent for 2022, and 2.43 per cent for 2023, which are representative of its actual labour mix and associated costs, are well below the Government of Alberta's 2022-2025 Fiscal Plan AWE assumptions of 3.4 per cent for 2022 and 3.8 per cent for 2023.[131] It is on that basis that the Commission finds ATCO Gas's proposed increase to be reasonable. Apex's proposed increase is likewise below the current updated AWE forecast and the Commission finds it to be reasonable on the same grounds.

140. The Commission does not find the CCA's evidence helpful in determining the reasonableness of ATCO Gas's and Apex's 2023 non-union salary escalations. The CCA's evidence set out union salary settlements which do not, in the Commission's view, directly translate to non-union employees. Union employees have different rights and obligations attached to their employment relationship such that union salary escalations cannot be transposed to non-union employees. Furthermore, non-union increases take into account several different factors typically not accounted for in union increases.[132] Similarly, the Commission agrees with ATCO Gas that CPI alone does not adequately reflect labour escalators.[133] In Decision 2012-237, the Commission considered this matter and introduced a separate labour component in the I factor approved for PBR1 and PBR2 plans.[134]

141. The Commission is satisfied that Mercer's inclusion of other distribution utilities in its peer group comparators for ATCO Gas and Apex does not create a circular reasoning chain. If all regulated utilities were removed from ATCO Gas's and Apex's peer group, the peer group would be less representative of the labour market for ATCO Gas and Apex. Additionally, the median 2022 salary increase budget projections would remain at three per cent.[135] Furthermore,

[130] Decision 26509-D01-2022 (Corrigenda): AltaLink Management Ltd., 2022-2023 General Tariff Application and 2020 Direct Assigned Capital Deferral Account Reconciliation Application, Proceeding 26509, February 11, 2022, paragraph 42.
[131] Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 16-18.
[132] Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 9-16.
[133] Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraph 6.
[134] Decision 2012-237, paragraphs 170-171.
[135] Exhibit 26616-X0234, ATCO Gas rebuttal evidence, Attachment 1, PDF page 7.

Mercer is widely regarded as a reputable source for benchmark data, and thus it should be expected that other utility and non-utility companies engage Mercer for salary recommendations.

142. With respect to the CCA's argument that employee wages were below median during the PBR term, and therefore should have no bearing on future increases since there is no measure that indicates there is an issue, the Commission notes that, in the context of non-union voluntary turnover rates increasing,[136] and the Government of Alberta's 2022-2025 Fiscal Plan AWE assumptions, the proposed increase is reasonable. In a similar vein, Apex provided updated data from February 2022 that showed the Alberta AWE index is higher than originally forecast by the Government of Alberta. In this context of upward pressure on wages, the Commission does not believe that it is reasonable to deny the proposed escalation rates. Doing so could negatively affect ATCO Gas's and Apex's ability to attract and retain employees.

143. Finally, the UCA pointed out that ATCO Gas implements its salary increases on April 1 of each year rather than January 1 and on this basis recommended that salary escalators be limited to three-quarters of the applied-for values. On this issue, the Commission agrees with ATCO Gas that the April 1 timing impact of the increase appears to be immaterial when compared to January 1 of each year.[137]

## 5.3 Placeholders

144. ATCO Gas and Apex included two placeholders in their applications: the 2023 opening rate base and cost of capital parameters. These are amounts that will be trued up when actual costs become available. In this section, the Commission addresses these requests.

145. Both ATCO Gas and Apex have included placeholders for their respective opening 2023 rate base consistent with Decision 26354-D01-2021,[138] because the 2021 and 2022 actual capital inputs and 2022 actual closing rate base were not available at the time of application filing. Both utilities produced their 2021 and 2022 capital forecasts generally relying on the same methodology used to forecast the 2023 capital costs.

146. ATCO Gas and Apex updated their respective 2021 capital costs with non-audited 2021 actual amounts on April 1, 2022. As set out in Section 7.1, the Commission examined the utilities' 2021 non-audited actual capital additions in this proceeding and, except as noted otherwise in this decision, finds these amounts to have been prudently incurred, subject to reviewing the explanations for variances between the non-audited 2021 actuals provided in April 2022 and audited actuals provided in Rule 005 filings. Therefore, the Commission directs ATCO Gas and Apex to incorporate the 2021 actual rate base, subject to the exceptions otherwise noted in this decision, into their compliance filings.

147. The utilities' 2022 actual capital costs will be updated with final (audited) actual amounts in 2023 following the release of the applicable Rule 005 filings to finalize 2023 opening rate base. Any changes or adjustments to the 2023 revenue requirements as a result of the finalization

[136] Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraph 19.
[137] Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 23-24.
[138] Decision 26354-D01-2021, paragraph 25. The Commission accepted the utilities' request for placeholder treatment for the opening 2023 rate base.

of the 2023 opening rate base will subsequently be trued up as part of an annual PBR rate adjustment filing.

148. ATCO Gas included in its application an equity thickness of 37 per cent and ROE of 8.5 per cent as placeholders pending a final determination of these parameters. Apex included an equity thickness of 39 per cent and ROE of 8.5 per cent as placeholders. In accordance with the findings in Decision 27084-D01-2022,[139] these are the final approved parameters for each utility in 2023.

# 6 2023 forecast O&M

149. In Decision 26354-D01-2021, the Commission directed each of the utilities to provide historical cost comparisons and related explanations to support their 2023 O&M cost forecast.[140] The Commission also prepared a schedule[141] for the filing by gas utilities of O&M expenses, based on prior Rule 005 filings from gas utilities, which presents information at a uniform system of accounts level.

150. The DFOs were directed to apply materiality thresholds from Bulletin 2020-25[142] to their O&M costs. DFOs were also directed to explain how they arrived at their 2023 forecast numbers, even for variances below the materiality thresholds.

## 6.1 ATCO Gas 2023 forecast O&M

151. To arrive at its requested overall 2023 forecast O&M of $242.5 million,[143] ATCO Gas primarily used a mechanistic approach. Specifically, approximately 85 per cent of its 2023 O&M forecast was derived under a mechanistic approach, with the remaining 15 per cent forecast using a non-mechanistic approach. For those O&M costs forecast using a mechanistic approach, ATCO Gas relied on the escalated 2018-2020 average as the basis for its 2023 forecast, as described in Section 3 above.

152. Overall, the 2023 forecast O&M of $242.5 million is $5.5 million below the escalated 2018-2020 average, $42.9 million below the escalated 2013-2017 average of $285.4 million, and $2.7 million higher than the indexed lowest cost year (2017) from the PBR1 term.[144]

153. Interveners took issue with ATCO Gas's forecast O&M costs. However, their objections and recommendations for lower O&M forecasts were primarily based on their general recommendation to use the lowest O&M cost year approach or include a separate efficiency offset to forecasts as part of rebasing costs and revenues. The Commission rejected these alternative approaches in Section 2 and found that the use of the escalated three-year historical average (2018-2020) is reasonable for the purposes of the current rebasing process.

[139] Decision 27084-D01-2022: 2023 Generic Cost of Capital, Proceeding 27084, March 31, 2022, paragraph 55.
[140] Decision 26354-D01-2021, paragraph 21.
[141] Proceeding 26354, Post-disposition documentation, Appendix 3- Final rebasing template- Gas, September 22, 2021.
[142] Bulletin 2020-25, Reducing Regulatory burden with materiality thresholds for review of cost of service rate applications, July 3, 2020.
[143] Exhibit 26616-X0193, ATCO Gas application update, Attachment 1, Updated Appendix A, Schedule 3a.
[144] Exhibit 26616-X0193, ATCO Gas application update, Attachment 1, Updated Appendix A, Schedule 3a.

154. As also set out in Section 2 of this decision, the Commission permitted the utilities to utilize a hybrid approach in forecasting their 2023 costs that employs both mechanistic and non-mechanistic methods. In this regard, the Commission finds that ATCO Gas's use of a mechanistic approach for forecasting some of its 2023 forecast O&M costs, and a non-mechanistic approach for other O&M costs, is reasonable.

### 6.1.1 ATCO Gas mechanistic O&M

155. ATCO Gas forecast the majority of its 2023 O&M and A&G costs under the mechanistic approach. ATCO Gas expressed its view that the applied-for O&M and A&G forecast costs developed using the mechanistic approach are representative of the costs that are reasonably expected to occur in 2023. ATCO Gas did not anticipate these costs to fluctuate materially from the amounts incurred over the 2018-2020 period.[145]

156. ATCO Gas utilized the mechanistic approach for gas management expenses, distribution expenses, general expenses, sales and transportation expenses, and non-IT customer accounting and A&G expenses.[146]

157. The Commission approves the use of the mechanistic approach by ATCO Gas to develop the forecasts for those O&M and A&G expenses that were characterized by predictable costs and similar drivers over time. In the Commission's view, generally, the items in this category did not require further detail or support because the forecast costs were aligned with ATCO Gas's past historical spending, which was undertaken while operating under the incentives of PBR. The Commission finds the costs underlying these forecasts to be less susceptible to volatility in 2023, and beyond, given their predictable spending pattern in the past. Furthermore, as set out in Section 5.1, for costs forecast using a mechanistic approach, the Commission is satisfied that the use of the 2018-2020 average, escalated by indexes approved in Section 5.2, results in a 2023 forecast that is reasonably reflective of the efficiencies achieved during the PBR2 term.

158. For these reasons, the Commission finds that ATCO Gas's O&M and A&G forecasts derived using the mechanistic approach, and adjusted using the escalation factors approved in Section 5.2, are reasonable. The Commission directs ATCO Gas to recalculate its 2023 O&M costs forecast under the mechanistic approach to reflect the escalation factors approved in Section 5.2 of this decision.

159. The remaining O&M and A&G forecasts that have been forecast using a non-mechanistic approach are addressed separately in the remainder of Section 6, and in Section 8.

### 6.1.2 ATCO Gas non-mechanistic O&M

160. O&M forecasts that do not utilize the mechanistic approach include IT costs (discussed separately in Section 8 below), non-IT incremental A&G costs, and the Emissions Reduction and Energy Efficiency (EREE) Program.

145 Exhibit 26616-X0018, ATCO Gas application, paragraph 101.
146 Exhibit 26616-X0018, ATCO Gas application, paragraph 102.

#### 6.1.2.1 Administrative and General (non-IT)

161. For non-IT A&G expenses, ATCO Gas first developed its base forecast by using the mechanistic approach and then increased this base forecast by incremental costs related to the innovation function.[147]

162. ATCO Gas explained that the innovation shared services group is responsible for building innovation capabilities within the organization and maintaining a consistent framework to identify, evaluate, and test innovative ideas. ATCO Gas stated that innovation was a newly centralized shared service function in 2020, and considering that the costs of this function are not reflected in the escalated 2018-2020 average, it requested that its share of these costs be added to the 2023 forecast.[148]

163. ATCO Gas also explained that its allocation of the innovation shared services group for 2023 is $1.2 million, which is 23.8 per cent of the overall forecast spend of $5 million for all ATCO companies combined, and is based on the approved general cost allocator.[149]

164. The Commission considers innovation to be a legitimate activity for regulated utilities, given that technology is changing the way the gas system is maintained, operated, and how risk is assessed. Given ATCO Gas's explanation on how the amount is calculated, and the fact that these costs are not reflected in the escalated 2018-2020 average, the Commission finds it reasonable to include these incremental costs in the A&G expense forecast for 2023. Accordingly, the 2023 forecast for A&G (non-IT) is approved.

#### 6.1.2.2 Emissions Reduction and Energy Efficiency Program

165. In the application, ATCO Gas forecast $860,000 in O&M expenses for the EREE program.[150] ATCO Gas stated that, as part of its strategy to address the federal *Greenhouse Gas Pollution Pricing Act*, *Canadian Net Zero Emissions Accountability Act*, and requirements to increase building energy efficiency to comply with "net-zero energy ready" building codes as outlined in the Pan-Canadian Framework on Clean Growth and Climate Change, it is proposing to provide the EREE programs to customers.[151]

166. ATCO Gas stated that EREE programs are fully consistent with leveraging the existing distribution infrastructure and providing multiple pathways toward the goal of efficient energy use with lower emissions. Furthermore, ATCO Gas stated it is globally recognized that increased investment in energy efficiency must be a strategic policy and regulatory priority since it is a low-cost decarbonization pathway essential to realizing emissions reduction goals. ATCO Gas stated that without continued innovations such as EREE, customers concerned with the issue of climate change may bypass natural gas in increasing numbers in favour of other fuel choices, which would in turn further reduce distribution system utilization, place upward pressure on costs for ratepayers who remain on the system, and increase long-term risks to the continued viability of natural gas distribution.[152] ATCO Gas submitted that EREE programs can reduce the cost of customer energy bills, enhance customer satisfaction, complement other decarbonization

147 Exhibit 26616-X0018, ATCO Gas application, paragraph 117.
148 Exhibit 26616-X0018, ATCO Gas application, paragraphs 118-121.
149 Exhibit 26616-X0135, AG-AUC-2022FEB17-003, PDF page 26.
150 Exhibit 26616-X0018, ATCO Gas application, Table 12, PDF page 44.
151 Exhibit 26616-X0018, ATCO Gas application, paragraph 125.
152 Exhibit 26616-X0018, ATCO Gas application, paragraphs 125-127.

initiatives, and educate customers on new technologies and services.[153] ATCO Gas also observed that in other Canadian and U.S. jurisdictions, utility EREE programs provide a widely adopted tool that has been highly successful in reducing gas costs for utility customers, and compared with other Canadian and U.S. jurisdictions, Alberta is an exception with respect to energy efficiency programming.[154]

167. The EREE program includes two separate subprograms: Customer Energy Literacy, and the EREE Program Planning, Design, and Implementation (PPDI) Study. ATCO Gas explained the objective of the Customer Energy Literacy subprogram, forecast to cost $150,000 in 2023, is to provide customers, homebuilders, and property developers with education and outreach materials regarding how the gas distribution system enables an affordable low-emissions future for meeting the space and water heating needs of Albertans. ATCO Gas also forecast an additional $360,000 to install 10 carbon capture units at 10 different school locations within its service area, and views this school program as part of ongoing and essential outreach to educate students on the innovations occurring in the gas distribution system.[155]

168. The EREE PPDI Study subprogram is forecast to cost $360,000 in 2023, and is intended to provide ATCO Gas with a comprehensive understanding of potential EREE programs for implementation, as well as program costs, decarbonization expectations, and net customer savings. ATCO Gas stated that this will inform its future EREE program delivery beyond 2023 and provide guidance to both ATCO Gas and the Commission with respect to a financial framework under which EREE programs may be delivered based on best practices in other jurisdictions.[156]

169. Calgary disagreed that the cost of the carbon capture units should be allowed, and stated that ATCO Gas was unable to provide tangible evidence demonstrating how this initiative will directly benefit the ratepayers, nor were specific figures offered that show this initiative will be a net benefit to ratepayers from either a financial or an environmental perspective. Calgary stated it is clear that this initiative will further the company's goodwill and serve as a community investment primarily promoting ATCO Gas at the expense of ratepayers. Calgary stated that such expenditures should accrue to the account of the shareholder.[157]

170. The UCA took issue with the overall EREE program on the basis that ATCO Gas had failed to provide detailed information about the costs and only identified a high-level summary of annual costs. The UCA stated that in this case, it may be more akin to a branding exercise, and education programs of this type should be handled by a centralized agency rather than by individual distribution utilities and entities, as this would avoid duplication of work across utilities and provide consistent messaging for utility customers. The UCA also submitted that implementing programs of this nature is not one of the core functions of a distribution utility. Finally, the UCA submitted that the Commission has already ruled in Decision 2011-450[158] that programs such as this, aimed at customer education and energy efficiency and demand side

[153] Exhibit 26616-X0018, ATCO Gas application, paragraph 128.
[154] Exhibit 26616-X0018, ATCO Gas application, paragraph 129.
[155] Exhibit 26166-X0018, ATCO Gas application, paragraph 133.
[156] Exhibit 26616-X0018, ATCO Gas application, paragraph 133.
[157] Exhibit 26616-X0199, Calgary written evidence, PDF pages 15-16.
[158] Decision 2011-450: ATCO Gas (a Division of ATCO Gas and Pipelines Ltd.), 2011-2012 General Rate Application Phase I, Proceeding 969, Application 1606822, December 5, 2011.

management, were not intended by the legislature to be among the functions of a gas distributor.[159]

171. For the reasons that follow, the Commission denies ATCO Gas's EREE program. The Commission finds that while EREE programs may be beneficial to all customers, it is not possible in the current proceeding to investigate and fully assess the best way to deliver EREE programs in Alberta. While ATCO Gas submitted that over 90 per cent of programming is funded by utility customers,[160] the Commission is not satisfied that ATCO Gas fully considered the advantages and disadvantages of an EREE program run by entities other than a utility to identify the best approach for its customers.

172. The UCA is the entity tasked by the provincial government to provide customer education on electric and natural gas utilities.[161] In this legislative and policy context, the Commission puts considerable weight on the submissions made by the UCA that customer confusion may result from unique and independent programs being undertaken by individual distribution utilities.

173. The Commission agrees with the UCA that there is potential for cost duplication and it may be more efficient to take a more coordinated approach to the EREE program. The Commission sees no reason why ATCO Gas could not work collaboratively with the UCA and other utilities to deliver coordinated EREE programming, particularly because ATCO Gas has indicated the EREE programs are in the public interest. Accordingly, ATCO Gas's EREE program is denied. The Commission directs ATCO Gas to remove the expenditures associated with these programs and initiatives from its 2023 forecast in its compliance filing.

### 6.2 Land and structures O&M and capital for ATCO Gas[162]

174. In its evidence, Calgary pointed to the fact that ATCO Gas reduced its total number of employees by approximately 25 per cent over the PBR1 and PBR2 terms. Calgary stated that ATCO Gas has not shown how this reduction has resulted in a corresponding reduction to costs required for office space. As well, Calgary observed that ATCO Gas has also allowed most office-based employees to work from home as a result of the pandemic. According to Calgary, these potential reductions in costs required for office space do not appear to have resulted in any savings for ratepayers in the application, and customers should not continue to pay for office space that is not being used.[163]

175. Accordingly, Calgary recommended an $87 million reduction in the 2023 opening rate base and a $12.7 million reduction to the 2023 O&M costs applied for by ATCO Gas in this proceeding, to reflect the reduced expenses associated with ATCO Gas's reduction in its total workforce and the higher proportion of (its remaining) employees working off site.[164] Calgary stated that in the absence of updated information, it calculated this cost reduction using ATCO

159 Exhibit 26616-X0318, UCA non-confidential oral argument, paragraphs 30-50.
160 Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 116-118.
161 *Government Organization Act*, Schedule 13.1, Section 3.
162 This section has been placed under O&M for convenience, although the discussion and findings have both O&M and capital implications.
163 Exhibit 26616-X0199, City of Calgary written evidence, PDF pages 16-17.
164 Exhibit 26616-X0199, City of Calgary written evidence, PDF page 19.

Gas's 2010 closing rate base, and an estimate of the reduction of the workforce between 2010 and 2023.[165]

176. For the reasons that follow, the Commission denies Calgary's recommendations. The Commission acknowledges ATCO Gas's assertion that it has been prudently managing owned and leased land and structures under PBR, that all of its leased and owned buildings are being used or required to be used for utility service, and that cost reductions associated with these are included in the escalated 2018-2020 average and are therefore being passed on to customers in 2023.[166] The Commission further accepts ATCO Gas's evidence that the majority of its buildings consist of operating and construction centres that were not vacated during the pandemic and that the majority of ATCO Gas's office-based employees have returned to working in the office a minimum of three days a week.[167]

## 6.3 Apex 2023 forecast O&M

177. Apex employed a mechanistic approach for the majority of its O&M accounts, with approximately 93 per cent of O&M costs forecast mechanistically. The exceptions are shared corporate services costs and existing deferral accounts which were forecast using a non-mechanistic approach.

178. Apex included the table below in its application to show that the net level of its 2023 forecast O&M cost of $47.87 million (line 21 in Table 11 below) was comparable to escalated historical averages:[168]

**Table 11. Apex summary of 2023 forecast O&M cost comparisons**

| | | | Indexed to 2023 $ | | |
|---|---|---|---|---|---|
| Line | O&M expense | 2023 Forecast | 2018-2020 Average | 2013-2017 Average | Lowest Year (2017) |
| | | ($000) | | | |
| 1 | Transmission (operating) | 890 | $ 890 | $ 874 | $ 965 |
| 2 | Distribution (operating) | 13,550 | 13,550 | 13,477 | 12,683 |
| 3 | General (operating) | 2,485 | 2,485 | 2,452 | 2,574 |
| 4 | Advertising & promotion | 69 | 69 | 62 | 62 |
| 5 | Customer accounting | 4,117 | 4,117 | 5,458 | 4,051 |
| 6 | Administration and general | 20,239 | 20,239 | 19,264 | 19,950 |
| 7 | Property tax expense | 161 | 161 | 152 | 157 |
| 8 | Transmission (maintenance) | 981 | 981 | 749 | 869 |
| 9 | Distribution (maintenance) | 1,332 | 1,332 | 1,394 | 1,287 |
| 10 | General (maintenance) | 730 | 730 | 641 | 604 |
| 11 | O&M, excluding shared corporate services costs and deferrals | 44,553 | 44,553 | 44,524 | 43,202 |
| 12 | Shared corporate services costs (Admin and General) | 3,688 | 3,504 | 3,655 | 3,681 |
| 13 | Shared corporate services costs capitalization | (1,291) | (722) | (571) | (564) |
| 14 | Shared corporate services costs – net | 2,397 | 2,782 | 3,084 | 3,117 |
| 15 | Deferrals (Admin and General) | 1,055 | 1,360 | 978 | 677 |
| 16 | Total O&M expense | 48,005 | 48,696 | 48,586 | 46,996 |

165 Exhibit 26616-X0199, City of Calgary written evidence, PDF page 18.
166 Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 97-98.
167 Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraph 100.
168 Exhibit 26616-X0023, Apex application, Table 10.3-1.

| Line | O&M expense | 2023 Forecast | Indexed to 2023 $ 2018-2020 Average | 2013-2017 Average | Lowest Year (2017) |
|---|---|---|---|---|---|
| | | ($000) | | | |
| | **Less: Disallowed/Not applied-for items** | | | | |
| 17 | Shared corporate services (inter-affiliate) costs | - | 1,199 | 1,284 | 1,341 |
| 18 | Community sponsorship | 41 | 41 | 44 | 41 |
| 19 | STIP | 95 | 95 | 79 | 129 |
| 20 | Total disallowed/not applied-for items | 137 | 1,335 | 1,407 | 1,511 |
| 21 | O&M expense – net | 47,869 | 47,360 | 47,180 | 45,485 |

179. As the above table shows, when considering inflation, Apex forecast a 2023 O&M annual net expense level comparable to both its escalated 2018-2020 average and the escalated 2013-2017 average. Comparing the 2023 forecast to the escalated 2018-2020 average, Apex limited its O&M forecast increase to one percent. Apex submitted that its lowest O&M year, 2017, had a variance to the 2023 forecast that is marginally greater than three per cent. Apex stated that its short-term cost savings in 2017 followed directly from temporary and unsustainable position vacancies caused by turnover throughout the year.[169] Apex added that its 2023 O&M forecast, when excluding shared corporate services costs and deferral accounts, is $44.55 million and this is only $29 thousand (or less than 0.1 per cent) higher than the escalated 2013-2017 average.

180. Apex stated in its application that it was able to maintain a limited O&M forecast increase through ongoing efforts to prudently manage costs by seeking efficiencies in an environment of increasing cost pressures, while continuing to provide safe and reliable service to its customers and maintain customer satisfaction.[170] Apex further explained that it managed increasing cost pressures in certain cost categories by finding cost reductions in other cost categories. By way of example, Apex explained it had experienced increasing cost pressures within the A&G category related to market-driven factors impacting the cost of employee benefits and changing trends in the IT landscape, such as the adoption of Cloud-based applications and increasing cybersecurity threats. Apex stated it was able to offset such pressures with cost reductions within, for example, the Customer Accounting category, which were achieved through initiatives such as the successful implementation of its Automated Meter Reading (AMR) Project.[171]

181. Interveners took issue with Apex's forecast O&M costs. However, their objections and recommendations for lower O&M forecasts were primarily based on their general recommendation to use the lowest O&M cost year rebasing approach or include a separate efficiency offset to forecasts. The Commission rejected these alternative approaches in Section 5.1 and found that the use of the escalated three-year historical average (2018-2020) is reasonable for the purposes of the current rebasing process.

182. As also set out in Section 2 of this decision, the Commission permitted the utilities to utilize a hybrid approach in forecasting their 2023 costs that employs both mechanistic and non-mechanistic methods. In this regard, the Commission finds that Apex's use of a mechanistic

169 Exhibit 26616-X0023, Apex application, paragraph 229.
170 Exhibit 26616-X0023, Apex application, paragraph 226.
171 Exhibit 26616-X0023, Apex application, paragraph 228.

approach for forecasting some of its 2023 forecast O&M costs, and a non-mechanistic approach for other O&M costs, is reasonable.

### 6.3.1 Apex mechanistic O&M

183. As previously noted, approximately 93 per cent ($44.55 million) of Apex's $47.87 million 2023 O&M forecast was developed using a mechanistic approach based on the escalated 2018-2020 average actual costs. Apex filed variance explanations to historical averages and the lowest indexed cost year (2017).

184. Below is a table from Apex's application. It shows that there was little variance between the historical years indexed to 2023 dollars and the 2023 forecast:[172]

**Table 12. Apex mechanistic O&M costs actual vs. 2023 forecast**

| Line | | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Actual O&M (indexed to 2023 $) ($000) | 44,672 | 44,563 | 44,871 | 45,312 | 43,202 | 44,295 | 44,798 | 44,566 |
| 2 | 2023 Forecast ($000) | 44,553 | 44,553 | 44,553 | 44,553 | 44,553 | 44,553 | 44,553 | 44,553 |
| 3 | Variance | -0.3% | 0.0% | -0.7% | -1.7% | 3.1% | 0.6% | -0.5% | 0.0% |

185. The Commission approves the use of the mechanistic approach by Apex to develop its forecasts for those O&M expenses that were characterized by predictable costs and similar drivers over time. In the Commission's view, generally, the items in this category did not require further detail or support because the forecast costs were aligned with Apex's past historical spending, which was undertaken while operating under the incentives of PBR. The Commission finds the costs underlying these forecasts to be less susceptible to volatility in 2023, and beyond. Furthermore, as set out in Section 5.1, for costs forecast using a mechanistic approach, the Commission is satisfied that the use of the 2018-2020 average, escalated by indexes approved in Section 5.2, results in a 2023 forecast that is reasonably reflective of the efficiencies achieved during the PBR2 term.

186. For these reasons, the Commission finds that Apex's O&M forecasts derived using the mechanistic approach, and adjusted using the escalation factors approved in Section 5.2 of this decision, are reasonable. The Commission directs Apex to recalculate its 2023 O&M costs forecast under the mechanistic approach to reflect the escalation factors approved in Section 5.2 of this decision.

187. The remaining O&M forecasts that have been forecast using a non-mechanistic approach are addressed separately in the remainder of Section 6.3.

### 6.3.2 Apex non-mechanistic O&M

188. Shared corporate services O&M costs and costs in approved deferral accounts were forecast non-mechanistically. Apex's reasons for forecasting these accounts non-mechanistically are provided in the sections below.

[172] Exhibit 26616-X0023, Apex application, Table 10.3-2.

#### 6.3.2.1 Apex non-mechanistic O&M – Shared corporate services

189. Apex applied to include $3.69 million in shared corporate services costs charged by its parent company, TriSummit Utilities Inc. (TSU), in its 2023 forecast. Apex explained that TSU provides corporate services to Apex on a cost-recovery basis, including governance, access to capital/financing, and corporate insurance services (shared corporate services).

190. Apex stated it did not use a mechanistic approach for the shared corporate services cost forecast due to a purported significant disparity between what is currently recovered in its rates and the actual costs associated with these corporate services. Apex stated that since 2013, on average, it has only recovered approximately two-thirds of the shared corporate services costs allocated to it by its parent company.[173] Apex noted that a portion of the historical shared corporate services costs, identified as Disallowed Inter-Affiliate Costs in Apex's 2023 COS rebasing schedules, have been subject to a disallowance.[174] For its 2023 forecast, Apex applied for full recovery of its shared corporate services costs.

191. Apex provided a report from its consultant, KPMG, to provide an independent evaluation of the reasonableness of the shared corporate services costs in the context of the Commission's three criteria used to assess the reasonableness of inter-affiliate charges. Those three criteria relied upon by the Commission, as explained in a prior decision involving AltaGas Utilities Inc. (Apex's name prior to its rebranding), are:[175]

(a) Are the services necessary for the provision of utility service?

(b) Are the costs allocated correctly?

(c) Would it be less expensive for the utility to provide the services itself or to seek a different third-party provider on a stand-alone basis?[176]

192. The Commission finds that the KPMG report did address the Commission's criteria for assessing the reasonableness of inter-affiliate charges, although it offered less compelling evidence in some areas such as insurance costs. In this area of costs, KPMG verified the various insurance policies procured by TSU for Apex by questioning the provider of TSU's insurance policies, Aon.[177] The Commission finds that questioning the insurance vendor is insufficient to assess the reasonableness of the costs, particularly for questions such as whether a different third-party provider should be sought, given the vendor's obvious conflict of interest in the matter. The Commission expects that, in the future, more effort will be made by Apex's chosen consultant to independently and objectively verify market value.

193. For the reasons set out in sections 6.3.2.1.1 to 6.3.2.1.3 below, the Commission is not persuaded by Apex's explanations for the large overall increases to TSU's 2022 and 2023 shared corporate services costs forecasts after several years of declining costs. The Commission also finds that the allocation percentage of shared corporate services costs to Apex from TSU should

[173] Exhibit 26616-X0023, Apex application, paragraph 266.
[174] Exhibit 26616-X0023, Apex application, paragraph 184.
[175] Decision 2012-091: AltaGas Utilities Inc., 2010-2012 General Rate Application – Phase I, Proceeding 904, Application 1606694, April 9, 2012, paragraph 437.
[176] Decision 2012-091, paragraph 436.
[177] Exhibit 26616-X0023, Apex application, KPMG Apex Review of Corporate Cost Allocation, PDF page 218.

be changed. Finally, the Commission directs Apex to remove any TSU STIP costs in the TSU total cost pool prior to allocating any corporate costs to Apex.

194. The Commission therefore directs Apex to reflect, in the compliance filing to this decision, the following adjustments to its 2023 shared corporate services costs forecast:

(i) Remove any TSU STIP costs, if any, from the 2021 shared corporate services forecast costs to be used as the basis of allocation to Apex.

(ii) Calculate the allowable 2023 forecast TSU cost pool to be allocated to Apex by escalating the 2021 forecast TSU cost pool to 2023 dollars using the inflation and customer growth escalators approved in Section 5.2 of this decision.

(iii) Allocate to Apex the allowable 2023 forecast TSU cost pool calculated above by using the allocation percentage of 42.2 per cent.

195. In Section 6.3.2.1.4, the Commission also comments on the possible impacts on Apex's shared corporate services costs of the potential acquisition of another utility.

#### 6.3.2.1.1 TSU shared corporate services cost pool

196. Apex provided the table below to compare the total historical TSU pool of costs and Apex's allocation of those costs from 2019 to 2023:

**Table 13. TSU shared corporate services costs allocated to Apex**

| Line | | 2019 Actual | 2020 Actual | 2021 Forecast | 2022 Forecast | 2023 Forecast |
|---|---|---|---|---|---|---|
| | | ($000) | | | | |
| 1 | Total TSU cost pool | 7,107 | 6,910 | 6,493 | 8,284 | 8,509 |
| 2 | AUI allocator | 42.4% | 43.2% | 43.3% | 43.3% | 43.3% |
| 3 | AUI shared corporate services costs | 3,013 | 2,984 | 2,814 | 3,590 | 3,688 |
| | **Escalated to 2023 dollars** | | | | | |
| 4 | AUI shared corporate services costs | 3,402 | 3,262 | 3,022 | 3,729 | 3,688 |

Source: Exhibit 26616-X0023, Apex application, Table 11.1-1.

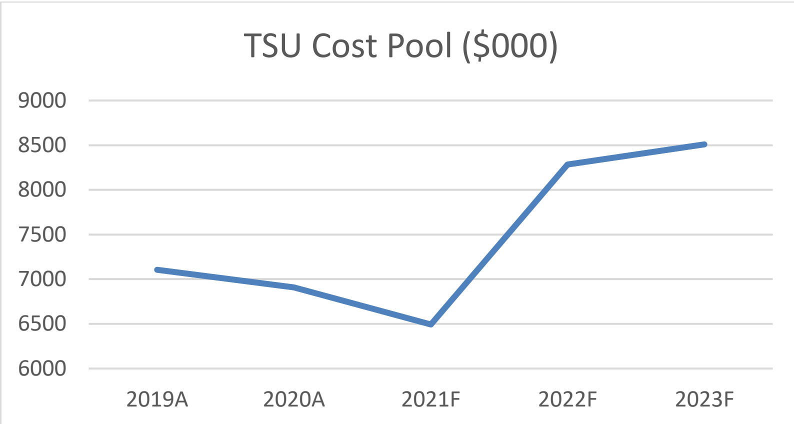
197. Apex explained that the TSU shared corporate services cost pool reflects no mark-up and excludes costs associated with: long-term incentive plans (LTIP) of TSU employees; supplemental executive retirement plans; strategic incentive plan costs; business development; corporate donations; promotion and advertising; and corporate social events.[178] Apex stated that, as a result of the exclusions, the allocable TSU cost pool represents approximately only two-thirds of TSU's total 2023 costs.

198. The Commission notes the allocation percentage of corporate costs to Apex has remained relatively constant over the 2019-2023 period (line 2 of Table 13). There are, however, significant fluctuations in the Total TSU Cost Pool (line 1 of Table 13). The annual costs declined from 2019 until 2021, but were forecast to increase by 28 per cent in 2022 from 2021, and increase by a further three per cent in 2023.

[178] Exhibit 26616-X0023, Apex application, paragraph 273.

199. Below is a graphic representation of the TSU cost pool changes:

**Figure 1. TSU shared corporate services total cost pool changes**




200. Apex provided a breakdown of the amounts allocated to it from TSU by cost category:

**Table 14. TSU shared corporate services costs allocated to Apex by cost category**

| Line | | 2019 Actual | 2020 Actual | 2021 Forecast | 2022 Forecast | 2023 Forecast |
|---|---|---|---|---|---|---|
| | | ($000) | | | | |
| 1 | Staff costs | $ 1,566 | $ 1,773 | $ 2,030 | $ 2,446 | $ 2,513 |
| 2 | Consulting & contracted services | 820 | 392 | 375 | 485 | 499 |
| 3 | Securities/Access to capital compliance | 276 | 248 | 175 | 188 | 193 |
| 4 | Board of directors' fees | 198 | 244 | 272 | 283 | 291 |
| 5 | Insurance | 162 | 131 | 152 | 187 | 192 |
| 6 | True-up (timing) | (9) | 196 | (190) | - | - |
| 7 | Apex shared corporate services costs | $ 3,013 | $ 2,984 | $ 2,814 | $ 3,590 | $ 3,688 |

Source: Exhibit 26616-X0023, Apex application, Table 11.1-2.

201. The two largest cost categories as shown in the table above are Staff Costs and Consulting & Contracted Services. They also account for the majority of the increase in allocated costs from 2019 to 2023.

202. Staff Costs include the salaries and benefits costs, associated professional dues, training, travel and office costs for TSU employees. The Consulting and Contracted Services category includes costs for accounting, tax, compensation, legal, IT, and communications consulting and contracted services. Apex stated that the services provided by consulting firms generally require specialized expertise or involve services for which only a small amount of time is required such that hiring a full-time employee to provide these services is not cost effective.[179]

203. Apex explained the increase in the Staff Costs category since 2019 is primarily due to TSU adding staff for services previously outsourced to consultants and for the addition of resources in 2022 to address new business requirements, including cybersecurity and Environmental, Social and Governance (ESG) reporting.[180] Apex also stated that in 2020 and

[179] Exhibit 26616-X0023, Apex application, paragraph 281.
[180] Exhibit 26616-X0023, Apex application, paragraph 279.

2021, there was significantly less travel and training due to COVID-19 travel restrictions and public health measures; however, these expenses were expected to return to pre-pandemic levels in 2022 and 2023.

204. In his evidence for the UCA, R. Bell combined the two cost categories in the table shown below to demonstrate that there was a significant increase in the Staff Costs and Consulting and Contracted Services costs categories, on a combined basis, in 2022:

**Table 15. R. Bell evidence – Staff costs and consulting and contracted services combined**

| Line | | 2019 Actual | 2020 Actual | 2021 Forecast | 2022 Forecast | 2023 Forecast | Increase [2019 vs 2023] | % |
|---|---|---|---|---|---|---|---|---|
| | | ($000) | | | | | | |
| 1 | Staff costs | 1,566 | 1,773 | 2,030 | 2,446 | 2,513 | 947 | 60.5 |
| 2 | Consulting & contracted services | 820 | 392 | 375 | 485 | 499 | -321 | -39.1 |
| | Combined | 2,386 | 2,165 | 2,405 | 2,931 | 3,012 | 626 | 26.2 |

Source: Exhibit 26616-X0203, UCA evidence, PDF page 46.

205. The above table shows that between 2019 actual results and the 2023 forecast, combined costs have increased by 26.2 per cent. During that time, Consulting and Contracted Services costs have indeed declined; however, increases to Staff Costs have outpaced those decreases, resulting in a net increase.

206. R. Bell noted that there was a net staffing and consulting increase in 2022 of $526,000 for Apex and that based on the allocation factor of 43.3 per cent, it equated to a total TSU cost pool increase of $1,214,000.[181] R. Bell noted that in an IR response to the Commission,[182] Apex stated that TSU is forecasting the addition of three employees in 2022 to address new business requirements for access to capital and corporate governance, such as ESG reporting and cybersecurity. Apex also noted that the three new positions would bring the total TSU staff contingent included in the cost pool to 16 positions.[183]

207. In a response to a Commission IR, Apex provided a further breakdown of the increase in combined TSU staff and consulting costs that were allocated to Apex between 2021 and 2022 (allocation increase of $526,000[184]) and 2021 and 2023 (allocation increase of $607,000[185]) as follows:[186]

(a) new staff (approximately $0.30 million)

(b) return to pre-pandemic travel and training levels (approximately $0.16 million)

(c) additional consulting fees (approximately $0.12 million) to support cybersecurity and ESG business requirements

181 Exhibit 26616-X0203, UCA evidence, PDF pages 46-47.
182 Exhibit 26616-X0106, AUI-AUC-2022FEB17-011(b).
183 Exhibit 26616-X0106, AUI-AUC-2022FEB17-011(d).
184 Table 15, Combined Total Year 2022 – Year 2021.
185 Table 15, Combined Total Year 2023 – Year 2021.
186 Exhibit 26616-X0106, AUI-AUC-2022FEB17-011(a).

(d) modest increase in corporate office costs (approximately $35 thousand)

(e) inflation

208. The variances set out in the aforementioned IR response represent only the amounts allocated to Apex out of the total incremental increase to the TSU cost pool of approximately $693,000[187] for the three new employees. This works out to a forecast average of $231,000 for each new employee. In an IR response to the Commission, Apex stated that these positions were filled to meet "… new business requirements for access to capital and corporate governance, such as ESG reporting and cybersecurity."[188]

209. R. Bell stated in his evidence regarding the new employee additions that cybersecurity and ESG are not new issues and that Apex has provided no reasons why the staff is needed now.[189] R. Bell recommended that Apex's shared services costs for 2023 be limited to the 2021 amount.[190]

210. The Commission is not persuaded by Apex's explanation for the large overall increases to TSU's 2022 and 2023 shared corporate services costs forecasts after several years of declining costs. Rather, the Commission agrees with R. Bell that cybersecurity and ESG reporting are not new issues[191] and that the timing of the forecast addition of staff and associated increase in consulting fees near the end of the PBR2 term is not consistent with the historical trend and is suspect. As explained in Section 4.1.2, the Commission is mindful of the incentive in the final year of a PBR plan for distribution utilities to increase their costs so as to increase going-in rates for the next PBR term. The Commission also notes that these new positions have not been filled yet.[192] This raises questions for the Commission as to the urgency of these proposed new hires. In the absence of any evidence to support the average forecast cost per new employee of $231,000, the Commission is unable to find the requested amount to be reasonable.

211. Finally, regarding Apex's claim that travel and training costs are expected to return to pre-pandemic levels, the Commission is of the view that the full effects of the pandemic on remote work arrangements and on-line conference and training attendance are still far from certain. In particular, it remains unclear to what extent changes in the way organizations operated in respect of continuing education and training during the pandemic will remain in place or be discarded in favour of pre-pandemic practices and procedures. What is clear, however, is that the pandemic has resulted in many new opportunities to reduce travel and training costs. Examples of this are the ability to attend conferences virtually rather than incurring often significant travel and accommodation costs and the ability to have employees attend a wider range of training sessions through online webinars at considerable savings. The Commission expects that, where appropriate, organizations will continue to use these types of remote attendance options to reduce travel and training expenses. The Commission further notes that Apex did not offer any evidence during this proceeding to explain why its travel and training costs will return to pre-pandemic levels, nor did it suggest that the remote attendance options widely used by businesses and

187 $300,000 / 0.433 = $692,841.
188 Exhibit 26616-X0106, AUI-AUC-2022FEB17-011(b).
189 Exhibit 26616-X0203, UCA evidence, PDF pages 47-48.
190 Exhibit 26616-X0203, UCA evidence, pages 47-48.
191 Exhibit 26616-X0203, UCA evidence, page 47.
192 Exhibit 26616-X0106, AUI-AUC-2022FEB17-010(a).

academic institutions during the pandemic will no longer be offered or considered to be reasonable alternatives.

212. For these reasons, the Commission agrees with the recommendation of R. Bell that the allowable 2023 forecast TSU cost pool used to allocate corporate costs to Apex should be kept at the 2021 forecast level subject to normalization to 2023 dollars using the inflation and customer growth escalation factors approved in Section 5.2. The Commission chose the 2021 TSU forecast cost pool rather than the 2021 TSU actuals as the basis to derive the 2023 forecast for two reasons: (i) the actuals were not provided on the record of this proceeding; and (ii) relying on forecasts is consistent with the overall purpose of the present 2023 COS review to approve the utilities' 2023 forecast revenue requirement.

#### 6.3.2.1.2 Allocation methodology

213. TSU costs are allocated to subsidiaries using a Modified Massachusetts Formula (MMF). Apex explained that the MMF allocator is the simple average of three quotients calculated as:[193]

(a) the total Property of the subsidiary subject to allocation (e.g., AUI) divided by TSU's total Property;

(b) the Payroll of the subsidiary subject to allocation divided by TSU's total Payroll; and

(c) the Normalized Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) of the subsidiary divided by TSU's total EBITDA.

214. According to Apex, the MMF allocator takes into account the size and complexity of the TSU entities and is an appropriate indicator of the degree to which different entities are likely to benefit from the services provided by TSU. Apex further stated that, "The services provided by TSU are not closely linked to, or driven by, the level of activity in its subsidiaries, which makes an allocation using a specific cost causation difficult to identify."[194]

215. The general corporate allocation factors were discussed by KPMG in its Review of Corporate Cost Allocations that Apex filed in support of its shared corporate service allocations. The KPMG report also compared the factors used in TSU's allocation methodology to those used by other utilities. KPMG provided the figure below to show this comparison:

[193] Exhibit 26616-X0023, Apex application, paragraph 302.
[194] Exhibit 26616-X0023, Apex application, paragraph 303.

**Figure 2. General corporate allocation factor comparison by KPMG**

| General Corporate Allocation Factors - Components | TSU | ATCO | EPCOR | ENMAX |
|---|---|---|---|---|
| Total Assets | | √ | √ | √ |
| Property Factor | √ | | | |
| Net Revenue | | √ | √ | |
| Gross margin | | | | √ |
| EBITDA | √ | | | |
| Labour Expense | √ | √ | | |
| Head Count | | | √ | √ |

Source: Exhibit 26616-X0023, Apex application, Figure 2-1: Composite Allocators, PDF page 202.

216. The KPMG report explained TSU's reasons for choosing a property factor to allocate corporate service support costs instead of relying on total assets, as do the comparator utilities. The report indicated that a key advantage of a property-based measure is that it focuses on the tangible assets required to provide utility services.[195] KPMG stated that, in contrast to total assets, the property factor is not affected by regulatory assets, which can fluctuate widely as a result of, among other things, delays in the collection and/or true-up of flow-through costs, such as those related to gas supply.

217. The Commission notes that in its 2010-2012 general rate application (GRA), AltaGas had argued that the cost of gas should be included in the composite allocator. As quoted in the associated Decision 2012-091:[196]

> AltaGas submitted that the UCA's suggestion to exclude the cost of gas from the allocator should be rejected. As indicated in AltaGas's rebuttal evidence, the composite allocator is used to allocate financial market service costs. As the commodity costs for the three entities have a significant bearing on the amount of capital required by AltaGas, Heritage Gas and Inuvik Gas, the company submitted that it would be inappropriate to remove this essential cost element from the allocation mechanism. Doing so would not adequately reflect the size of the working capital requirements of each affiliate. [footnotes removed]

218. In Decision 2012-091, the Commission accepted AltaGas's rationale for including the cost of gas in the revenue component of the composite allocator given that "AltaGas has stated that the cost of gas has a significant impact on the capital required and there is no evidence on the record to challenge this assertion."[197]

219. The Commission finds total assets to be a more reasonable cost allocator for use in the MMF formula for the following reasons: (i) total assets is one of the three MMF composite allocators used consistently by the comparator utilities and was previously used by AltaGas; (ii) the Commission has previously found that the cost of gas should be included in the composite allocator; and (iii) corporate service support costs are driven by more than the net

[195] Exhibit 26616-X0023, Apex application, KPMG Review of Corporate Cost Allocation report, Section 2.4.1, PDF page 204.
[196] Decision 2012-091, paragraph 411.
[197] Decision 2012-091, paragraph 413.

book value of property owned by each affiliate. The Commission therefore directs Apex to use total assets in place of the property factor as one of the three MMF composite factors for its 2023 forecast TSU corporate allocations, and to reflect this change in its compliance filing.

220. In response to a Commission IR,[198] Apex showed that using total assets, the Apex shared corporate services allocation percentage would be 42.2 per cent for 2023 (as compared to the 43.3 per cent when using the property factor). Therefore the Commission expects this to be reflected in the compliance filing.

#### 6.3.2.1.3 Other shared corporate services matters – TSU STIP costs

221. The staff costs category also includes STIP payments to TSU employees of approximately $0.13 million in the 2023 forecast shared corporate services costs allocated to Apex.[199] In its application, Apex acknowledged that the Commission has generally denied the recovery of shareholder-related incentive compensation from customers.[200] However, Apex argued that STIP costs for TSU employees should be included in its revenue requirement because, in a PBR environment, where a primary goal is to create the same efficiency incentives as those experienced in a competitive market, it is not unreasonable to suggest that incentive plan costs tied to financial goals may lead to tangible benefits for customers. Apex submitted that STIP incentives tied to growing revenues and reducing expenses promote improvements in productivity, which translate into lower costs for customers.

222. Apex was also asked in a Commission IR to explain why it would be reasonable to assume that a regulated utility's PBR incentives were the same as those of its corporate parent's employees who are not subject to PBR and may have different objectives.[201] Apex responded that STIP tied to financial performance ensures that TSU employees are incented in the same manner as Apex employees. Apex added that, in the absence of STIP tied to financial performance, there is less of an incentive for employees to pursue efficiencies as there is no direct linkage between their compensation, productivity improvements and lower corporate costs. Apex also reiterated that TSU excluded from the TSU shared services cost pool not only 100 per cent of the compensation, including STIP, for TSU executive, management and temporary employee positions devoted to business development, but also the office costs associated with those positions.

223. When asked in another Commission IR how STIP corporate financial targets, such as increasing TSU normalized net income, directly benefit the regulated utility ratepayers, Apex replied that if TSU increases revenue through companies other than Apex, the EBITDA allocation factor for the other companies will increase relative to Apex.[202] This, in turn, would reduce Apex's portion of the shared services costs, and benefit ratepayers through lower shared services costs.

224. Apex argued that STIP for TSU employees should be considered integral to the PBR framework. According to Apex, STIP payments incent TSU employees to grow revenue and

198 Exhibit 26616-X0106, AUI-AUC-2022FEB17-014(a).
199 Exhibit 26616-X0023, Apex application, paragraph 278.
200 Exhibit 26616-X0023, Apex application, page 77, footnote 60.
201 Exhibit 26616-X0106, AUI-AUC-2022FEB17-009(a).
202 Exhibit 26616-X0106, AUI-AUC-2022FEB17-009(c).

reduce costs, which can then lower the corporate allocation for services to Apex to the ultimate benefit of Apex's customers.

225. In Decision 2007-094, the Alberta Energy and Utilities Board (the Commission's predecessor) wrote:[203]

> The Board considers that where the utility has demonstrated that the benefits will ultimately add to the efficiency of the utility, there is merit to the applicable portion of the STIP being included in revenue requirement. However, where the benefit is increased return or other benefits to shareholders, the Board does not view funding that portion of the STIP through rates to be appropriate. This is consistent with previous Board decisions.

226. The Commission is not persuaded that the benefits of a corporate STIP will ultimately add to the efficiency of Apex, or that TSU employee incentives that may be more aligned with growing its own business are entirely aligned with Apex's incentives of running a regulated utility. TSU, as a non-regulated for-profit entity, already has the same incentives as any competitive business, that is, to keep costs to a minimum while maximizing revenues. Natural monopolies, such as local gas distribution utilities, have few, if any, incentives to reduce costs under traditional COS regulation. The same cannot be said, however, about PBR where cost-cutting incentives for regulated utilities have been specifically designed to mimic, or produce results comparable to, those of competitive businesses. Additionally, while Apex stated that TSU business development costs are not included in the STIP cost pool, the Commission has no oversight of TSU's costs. The Commission also appreciates that accurately segregating activity costs where employees perform multiple roles for a company (e.g., business development vs. day-to-day operations) can be an accounting challenge.

227. On balance, the Commission finds there to be insufficient evidence to support the proposition that Apex's ratepayers will be better off paying for TSU's employee STIP program benefits and incentives than these costs being borne by TSU's shareholders. The Commission, therefore, denies the inclusion of any TSU employee STIP costs in the corporate shared service allocation to Apex. If any TSU employee STIP costs were included in the 2021 TSU forecast cost pool (that will be used as the basis for Apex's 2023 forecast allocation as directed earlier in this decision), the Commission directs that they be removed to ensure that Apex's 2023 forecast shared corporate services costs exclude any TSU employee STIP costs.

#### 6.3.2.1.4 Apex's parent company acquisition of ENSTAR

228. In oral testimony, Graeme Feltham, president of Apex, stated that Apex's parent company, TSU, announced on the morning of May 26, 2022, that it was acquiring the Alaskan gas utility ENSTAR in a transaction expected to close in 2023.[204] He explained that it was a material transaction for the parent company. ENSTAR has 155,000 customers compared to TSU's 135,000 customers, including Apex's 80,000 customers. If the transaction closes, G. Feltham expected that the percentage of the corporate services allocation to Apex would decrease.[205]

203 Decision 2007-094: AltaGas Utilities Inc., 2007 General Rate Application Phase I, Application 1494406, December 11, 2007, PDF page 38.
204 Transcript, Volume 3, page 190, lines 2-4.
205 Transcript, Volume 3, page 191, lines 5-18.

229. G. Feltham stated that the transaction was contingent on regulatory approvals and therefore the timing of the acquisition was uncertain. G. Feltham confirmed that the corporate services allocation methodology as presented in the application would not change if the acquisition takes place.[206] Based on this, G. Feltham suggested, in the interest of regulatory efficiency, that the Commission review and approve the applied-for shared corporate services allocation methodology and make a decision based on the information and forecast of costs on the record of this proceeding. If the acquisition transaction proceeds and subsequently receives regulatory approval, G. Feltham explained that Apex would offer to true up the forecast amount to actuals. The Commission has treated G. Feltham's offer to true up as a de facto request for deferral account treatment.

230. The Commission does not approve the deferral account treatment of Apex's shared corporate services costs. While the Commission acknowledges the significance of the pending transaction, it considers that Apex and its parent, TSU, are well positioned to manage their shared corporate services costs both pre- and post-acquisition as these costs are entirely within their control. The Commission acknowledges G. Feltham's expectation that as a result of the acquisition, the percentage of the corporate services allocation to Apex may decrease as corporate costs will be allocated to a larger pool of subsidiaries.[207] The Commission finds that the reductions to Apex's shared corporate services costs and the reduction to the allocation percentage directed in previous sections of this decision reflect the reasonable costs of shared corporate services that are expected to be delivered to Apex by TSU in 2023, whether or not the acquisition proceeds. To the extent Apex or its corporate parent reduce the shared corporate services costs in 2023 or during the PBR3 term (including through acquisition of other entities), customers will benefit from these reductions at the time of the next rebasing.

#### 6.3.2.2 Apex non-mechanistic O&M – deferrals (A&G)

231. Apex explained that its 2023 forecast O&M costs include the following existing Y factors subject to deferral account treatment in the current PBR plan:

- Natural Gas Settlement System Code (NGSSC) costs
- AUC assessment fees
- UCA assessment fees
- Intervener hearing costs
- Production abandonment costs

232. The following table summarizes Apex's 2023 forecast for its O&M deferral accounts:

[206] Transcript, Volume 3, page 193, lines 6-11.
[207] Transcript, Volume 3, page 191, lines 5-18.

**Table 16. Summary of Apex's 2023 O&M deferral accounts**[208]

| Line | | 2023 Forecast ($000) |
|---|---|---|
| 1 | NGSSC operating costs | $ 421 |
| 2 | Intervener proceeding costs | 14 |
| 3 | AUC assessment fees | 261 |
| 4 | UCA assessment fees | 64 |
| 5 | Production abandonment costs | 295 |
| 6 | Total costs | $ 1,055 |

233. The forecast for each O&M deferral account was explained in Apex's application. The Commission notes that, as deferral accounts will subsequently be trued up to actuals and be afforded placeholder treatment in the meantime, there is no forecast risk.[209]

234. The Commission finds that with the exception of NGSSC operating costs, the forecast costs in Apex's 2023 O&M deferral accounts are reasonable, and are approved. While the Commission approves the 2023 forecast NGSSC operating costs as reasonable, the Commission denies deferral account treatment for these costs for the reasons set out in Section 7.3.2.3. The Commission directs Apex to remove the NGSSC operating costs from the O&M deferrals (A&G) expense account, as shown in Table 16 above, and reclassify these costs as general distribution operating costs.

# 7 2023 forecast capital additions

235. In Decision 26354-D01-2021,[210] the Commission provided direction on the methodology for developing the capital component of the DFOs' 2023 revenue requirement forecasts including the use of mechanistic and bottom-up approaches for determining the 2023 forecast capital additions and related items such as capital assets, i.e., property, plant and equipment in service, accumulated depreciation and depreciation expense and contributions in aid of construction. The Commission also prepared a rebasing schedule template for filing capital costs.

236. The Commission directed the utilities to provide comparisons to historical costs and to apply materiality thresholds from Rule 005. DFOs were directed to explain how they arrived at the 2023 forecast numbers, even for variances below the materiality thresholds.[211]

## 7.1 Prudence review

237. In Bulletin 2021-04, the Commission determined that it would include the assessment of prudence of actual capital costs incurred during the PBR2 term as part of the present COS review of 2023 forecast costs. The Commission has assessed the capital costs of each of ATCO Gas and Apex, and ATCO Electric IT/CIS costs incurred in the years 2018 to 2020 and finds them to be prudently incurred unless specifically addressed in this decision.

208 Exhibit 26616-X0023, Apex application, Table 10.2.2-1.
209 Decision 26354-D01-2021, paragraph 52.
210 Decision 26354-D01-2021, Section 4.2.
211 Decision 26354-D01-2021, Section 4.3.

238. The applications included 2021 forecast costs on a placeholder basis. Consistent with the Commission's direction, ATCO Gas and Apex filed their non-audited 2021 actual costs on April 1, 2021.[212] [213] As also directed by the Commission,[214] the utilities did not do a comprehensive update of their applications; however, they did provide detailed tables setting out their 2021 actual capital costs accompanied by variance explanations in relation to filed 2021 forecasts.[215] [216] In this proceeding, the Commission undertook an assessment of the utilities' 2021 non-audited actual costs.

239. Based on its assessment, the Commission is prepared to accept the 2021 non-audited actual costs as prudently incurred unless noted otherwise in this decision. This finding is also subject to the Commission's review of each utility's explanations for any variances between the non-audited 2021 actual expenditures filed in this proceeding in April 2022 and audited costs reported in 2021 Rule 005 filings. The Commission directs the utilities to file these explanations as part of their compliance filings to this decision.[217]

240. Lastly, the Commission has reviewed the utilities' 2022 forecast costs and, with the exception of cost items specifically addressed in this decision, finds them to be reasonable and approves them on a placeholder basis. The mechanistically forecast 2022 programs reflect the escalated 2018-2020 average, albeit using the escalation factors as applied for by the utilities (and not adjusted in accordance with this decision). Given the placeholder nature of these forecasts, the Commission will not require the DFOs to restate them to reflect the escalation factors approved in this decision, unless the utilities see value in doing so (for example, where they are restated to assist in understanding the calculation for a restated 2023 forecast). For non-mechanistic programs, the Commission has assessed the 2022 forecasts together with 2023 forecasts and finds them to be reasonable on a placeholder basis, unless stated otherwise in this decision.

241. In making the above determinations, the Commission also maintains the view that actual costs incurred under the incentives of PBR should generally be deemed prudent (as the utilities are incented to reduce costs) and not be subjected to the same level of scrutiny as expenditures incurred under COS regulation. However, as noted in Section 4.1, the incentives to pursue efficiencies weaken as the end of the PBR term approaches and there is an incentive in the final year of a PBR plan for distribution utilities to increase their costs so as to increase going-in rates for the next PBR term. The Commission is mindful of this weakening of incentives. As set out in Decision 26354-D01-2021, the Commission may examine any variances between the actual opening 2023 rate base and the 2022 placeholder amount in a future proceeding, which could

212 Exhibit 26616-X0192, ATCO Gas 2023 COS application 2021 preliminary (unaudited ) actuals, April 1, 2022; Exhibit 26616-X0194,Attachment 1 - ATCO Gas 2021 preliminary (unaudited ) actuals vs forecast, April 1, 2022.

213 Exhibit 26616-X0195, AUI Preliminary Full-Year 2021 Actuals and Updates, April 1, 2022; Exhibit 26616-X0196, Appendix 1 – 2021 O&M and Capital Variances, April 1, 2022.

214 Exhibit 26616-X0191, AUC letter – Clarification on April 1 filing and ATCO Electric request to change process, March 29, 2022, paragraph 7.

215 Exhibit 26616-X0192, ATCO Gas 2023 COS application 2021 preliminary (unaudited ) actuals, April 1, 2022; Exhibit 26616-X0194,Attachment 1 - ATCO Gas 2021 preliminary (unaudited ) actuals vs forecast, April 1, 2022.

216 Exhibit 26616-X0195, AUI Preliminary Full-Year 2021 Actuals and Updates, April 1, 2022; Exhibit 26616-X0196, Appendix 1 – 2021 O&M and Capital Variances, April 1, 2022.

217 Transcript, Volume 5, page 605.

result in disallowances and potential changes to going-in rates if the Commission is not persuaded that the 2022 actual capital additions were prudent.[218]

## 7.2 ATCO Gas 2023 forecast capital additions

242. To arrive at its requested overall 2023 capital forecast, ATCO Gas used a hybrid approach, which consisted of a combination of mechanistic forecasts for recurring programs and non-mechanistic forecasts for non-recurring or new programs. The mechanistic forecasts were based on a three-year escalated average of ATCO Gas's 2018 to 2020 capital additions. The non-mechanistic forecasts used a bottom-up forecasting methodology.[219]

243. Consistent with Decision 26354-D01-2021,[220] ATCO Gas categorized its capital program as either recurring or non-recurring. Recurring capital programs are predictable and are expected to occur in the future. ATCO Gas indicated that its non-recurring capital programs are either new, not part of ATCO Gas's ongoing business operations, programs whose drivers have changed or where costs are not forecast to continue to be incurred in 2023 and beyond.[221]

244. ATCO Gas forecast its capital additions as shown in the tables below.

**Table 17. ATCO Gas North 2020-2023 actual and forecast capital additions**

| Capital program | 2020 Actual | 2021 Forecast | 2022 Forecast | 2023 Forecast | Forecast methodology |
|---|---|---|---|---|---|
| | ($000) | | | | |
| Growth | 44,235 | 50,120 | 51,680 | 53,535 | Mechanistic |
| System Sustainment | 40,439 | 33,931 | 34,988 | 36,243 | Mechanistic |
| Infrastructure Renewal | 14,170 | 33,762 | 34,813 | 36,062 | Mechanistic |
| Metering | 10,739 | 12,276 | 12,658 | 13,113 | Mechanistic |
| General Support | 33,973 | 26,607 | 27,436 | 28,420 | Mechanistic |
| Commercial Below Ground Entry | - | - | - | - | Non-mechanistic |
| CIS Replacement | - | 8,275 | 46,725 | - | Non-mechanistic |
| **Total** | **143,557** | **164,971** | **208,300** | **167,373** | |

Source: Exhibit 26616-X0193, Attachment 1, Updated[222] Appendix A, ATCO Gas Commission Template, Schedule 4.4a - North.

**Table 18. ATCO Gas South 2020-2023 actual and forecast capital additions**

| Capital program | 2020 Actual | 2021 Forecast | 2022 Forecast | 2023 Forecast | Forecast methodology |
|---|---|---|---|---|---|
| | ($000) | | | | |
| Growth | 39,944 | 44,465 | 45,808 | 47,461 | Mechanistic |
| System Sustainment | 30,177 | 42,272 | 43,549 | 45,121 | Mechanistic |
| Infrastructure Renewal | 10,926 | 19,843 | 20,443 | 21,181 | Mechanistic |
| Metering | 10,500 | 9,687 | 9,980 | 10,340 | Mechanistic |
| General Support | 23,845 | 20,851 | 21,481 | 22,257 | Mechanistic |

218 Decision 26354-D01-2021, paragraph 25.
219 Exhibit 26616-X0018, ATCO Gas application, PDF page 49, paragraphs 152-153.
220 Decision 26354-D01-2021, paragraph 30(iii)-(iv).
221 Exhibit 26616-X0018, ATCO Gas application, PDF page 48, paragraphs 147-149.
222 Exhibit 26616-X0102, ATCO Gas updated Appendix A to reflect the withdrawal of the hydrogen projects from its application as directed in AUC letter - Preliminary jurisdictional issues - hydrogen projects.

| Capital program | 2020 Actual | 2021 Forecast | 2022 Forecast | 2023 Forecast | Forecast methodology |
|---|---|---|---|---|---|
| | ($000) | | | | |
| Commercial Below Ground Entry | - | - | - | - | Non-mechanistic |
| CIS Replacement | - | 8,275 | 46,724 | - | Non-mechanistic |
| Maintenance Depot Operating Centre Replacement | - | - | - | 4,000 | Non-mechanistic |
| **Total** | **115,391** | **145,393** | **187,985** | **150,359** | |

Source: Exhibit 26616- X0193, Attachment 1, Updated[223] Appendix A, ATCO Gas Commission Template, Schedule 4.4a - South.

### 7.2.1 Recurring capital (mechanistic approach)

245. As noted earlier, ATCO Gas forecast the 2023 costs for all of its recurring programs using the mechanistic approach.

246. The Commission approves the use of the mechanistic approach by ATCO Gas to develop the forecasts for capital additions that were characterized by predictable costs and similar drivers over time. In the Commission's view, generally, the capital additions in this category did not require further detail or support because the forecast costs were aligned with ATCO Gas's historical spending, which was undertaken while operating under the incentives of PBR. Such forecasts were also supported by way of variance explanations at the appropriate level, as and when required. The Commission finds the costs underlying forecasts to be less susceptible to volatility in 2023, and beyond, given the predictable pattern in the past. Furthermore, the Commission determined in Section 5.1 that for costs forecast using a mechanistic approach, the use of the 2018-2020 average, escalated by indexes approved in Section 5.2, results in a 2023 forecast that is reasonably reflective of the efficiencies achieved during the PBR2 term.

247. The Commission finds that the 2023 forecast costs for those programs that were forecast mechanistically are reasonable and approves them as filed, subject to using the escalation factors approved in Section 5.2. Accordingly, the Commission directs ATCO Gas to provide updated amounts in the compliance filing.

### 7.2.2 Non-recurring or new capital (non-mechanistic approach)

248. The Commercial Below Ground Entry, Maintenance Depot Operating Centre Replacement and CIS Replacement projects that were forecast using the non-mechanistic approach are addressed in the following sections.

#### 7.2.2.1 Commercial Below Ground Entry

249. ATCO Gas indicated that the Commercial Below Ground Entry Project is required to address a potential safety issue that can occur on straight-in below grade entries when an outside force acts on the service line causing distribution pressure gas to be released into a building. No capital additions are forecast for 2023; however, as explained by ATCO Gas, the project is required to be retained for continuity of historical rate base. ATCO Gas noted that any future work performed under this project will be completed in the normal course of business under recurring capital.[224] Given ATCO Gas's explanation and that no capital additions are forecast for

[223] Exhibit 26616-X0102, ATCO Gas updated Appendix A to reflect the withdrawal of the hydrogen projects from its application as directed in AUC letter - Preliminary jurisdictional issues - hydrogen projects.
[224] Exhibit 26616-X0018, ATCO Gas application, PDF page 55, paragraph 173.

2023, there are no amounts associated with this project for the Commission to consider for the 2023 test year.

#### 7.2.2.2 Maintenance Depot Operating Centre Replacement

250. To address safety and functionality concerns, ATCO Gas proposed to replace its existing Maintenance Depot Operating Centre located within the city of Calgary. ATCO Gas explained that the existing facilities, which were built in 1969 and 1977, are aging. A new location and new facilities are required to accommodate larger and more specialized equipment and to address site access challenges due to congestion caused by development in the surrounding area.[225]

251. ATCO Gas plans to purchase land in 2023, which will first be used to relocate a portion of the storage and functions from the existing buildings. The construction of new facilities is expected to take place in the 2024-2025 time period. The cost of the land is forecast to be $4.0 million in 2023. ATCO Gas provided a high-level estimate of the remaining costs for the project in the amount of $18.7 million in 2021 dollars.[226]

252. The Commission asked several IRs on the nature, scope, level of expenditures and timing of the proposed Maintenance Depot Operating Centre Replacement Program.[227] Based on the responses provided by ATCO Gas, the Commission is persuaded that the new location and new facilities are required, and that the land purchase costs and the timing of the project are reasonable. The Commission's finding is based in part on ATCO Gas's evidence that the current site location is no longer adequate to meet ATCO Gas's operational needs. Accordingly, the Commission approves the 2023 forecast capital additions of $4.0 million for this project as filed.

#### 7.2.2.3 CIS Replacement

**Background**

253. In their respective applications, both ATCO Gas and ATCO Electric[228] (collectively referred to as the ATCO Distribution Utilities) stated that they are undertaking a replacement of their CIS, which is an in-house developed, custom-built application that currently supports customer care and billing (CC&B) functions, as well as meter management capabilities. The ATCO Distribution Utilities stated that the need for this replacement is driven specifically by the risk of system error or failure given the complexity and age of the legacy CIS, the declining knowledge base to support the legacy application, and the risk of cybersecurity attacks. The ATCO Distribution Utilities did not forecast any 2023 capital additions related to the CIS Replacement project, explaining that the program will be completed in 2022 and the forecast capital additions will be updated to reflect actual costs.[229]

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225 Exhibit 26616-X0018, ATCO Gas application, Appendix H.2 – Maintenance Depot Operating Centre Replacement Business Case, PDF page 194.
226 Exhibit 26616-X0018, ATCO Gas application, Appendix H.2 – Maintenance Depot Operating Centre Replacement Business Case, PDF page 206.
227 Exhibit 26616-X0135, AG-AUC-2022FEB17-010 and AG-AUC-2022FEB17-011.
228 ATCO Electric's CIS application was transferred to this proceeding in Proceeding 26615, Exhibit 26615-X0426, AUC letter - Process and scope for oral questioning and oral argument, paragraphs 5-6.
229 Exhibit 26616-X0018, ATCO Gas application, paragraphs 187-189; Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, paragraphs 174-177.

254. The Commission is satisfied that, given the risk of the continued use and operation of the existing ATCO Distribution Utilities' CIS, the need for replacement is warranted.

255. Interveners expressed concerns with the ATCO Distribution Utilities' adoption of a software as a service (SaaS) solution, project timing, and the level of expenditures. Each of these concerns is addressed in the paragraphs that follow.

### Software as a service

256. Jim Stephens, on behalf of Calgary, raised a concern that the ATCO Distribution Utilities' business cases did not identify and address the fact that the utilities would be early adopters of the Oracle CCS SaaS solution, and that early adopters cannot easily find knowledgeable and skilled resources, leading to application errors, project delays and project implementation costs exceeding project budgets.[230]

257. The Commission does not agree with Calgary's concerns. The Commission notes that ATCO Gas was aware of this risk, which was identified by TMG Consulting in its December 2019 assessment.[231] TMG is an advisory consultant with considerable experience in CIS implementations in the utility industry that was retained by the ATCO Distribution Utilities to assist in the CIS implementation. The ATCO Distribution Utilities also noted that the Oracle CCS product is based on the on-premise Oracle CC&B software that has been in the industry since the mid-2000s, and explained that the working familiarity with Oracle CCS has increased to the point where the ATCO Distribution Utilities would no longer be considered an "early adopter."

258. TMG's analysis also confirmed that other utilities are moving to SaaS environments.[232] Greg Galluzzi of TMG identified that a major vendor indicated that it will no longer issue perpetual software licences. Instead, the major vendor will only sell cloud SaaS licences.[233] As a result, the Commission is satisfied that the ATCO Distribution Utilities' evaluation of the SaaS solution adequately considered cost, risk and solution viability, among other things.

### Timing of project

259. J. Thygesen, on behalf of the CCA, stated that while the concerns and issues the CIS Replacement project were meant to address are not new, the ATCO Distribution Utilities decided to delay completion of this project until just before 2023, a COS rebasing year. Accordingly, J. Thygesen expressed the view that the project is not being completed under PBR incentives. Instead, the ATCO Distribution Utilities are bringing the CIS into service in 2022, when the "half year rule" applies and the income statement impact is minimized, with the full impact occurring in 2023. J. Thygesen claimed that the ATCO Distribution Utilities waited until 2020 to commence active development of the system, despite peak errors with the ATCO Distribution Utilities' existing CIS software occurring in 2016. J. Thygesen recommended that, due to this

230 Exhibit 26616-X0208-C, Stephens Consulting evidence (confidential), PDF pages 23-24; Proceeding 26615, Exhibit 26615-X0304, Evidence of Stephens Consulting, PDF pages 7-8.
231 Exhibit 26616-X0233-C, ATCO Gas rebuttal evidence, paragraph 278.
232 Exhibit 26616-X0233-C, ATCO Gas rebuttal evidence, paragraphs 284-286; Proceeding 26615, Exhibit 26615-X424-C, ATCO Electric rebuttal evidence, paragraphs 103-109.
233 Transcript, Volume 1 - Confidential, page 79.

four-year delay, only the 2026 revenue requirement should be included in rates, to account for the four-year impact on the income statement.[234]

260. Calgary stated that "it would appear that the project was scheduled in such a way to maximize cost to the ratepayer, and revenue to ATCO, by loading up rate base just prior to the 2023 COS test year."[235] J. Stephens, on behalf of Calgary, stated that it was surprising to see the ATCO Distribution Utilities proceed with the replacement of several back-office applications (Project Cirrus) before the CIS Replacement project, given the risks identified in the business case.[236] He stated that ATCO Pipelines' solution to not having premier support was to subscribe to Oracle's extended support. If the ATCO Distribution Utilities could have used the same solution, and subscribed to the extended support, they would have avoided the risks of not having premier support and thus could have implemented the CIS project earlier rather than waiting for Project Cirrus to be completed. J. Stephens further stated that the additional delay in implementing the CIS project only increased the risks identified by the ATCO Distribution Utilities.[237]

261. The Commission finds that the timing of the CIS project is reasonable. The ATCO Distribution Utilities stated that in 2017 they determined that replacement of the CIS would be placed on hold until Project Cirrus was completed, since this would reduce the amount of back office interim states necessary to transform the front office. The ATCO Distribution Utilities stated that the decision was based on several factors, including the complexity of proceeding with both projects concurrently, competition for concurrent IT governance and technical expertise and resources, and the ability for the selected system integrators to deliver quality results on both programs concurrently.[238]

262. The Commission agrees with the ATCO Distribution Utilities that it takes time to plan a complex system replacement, and finds that the ATCO Distribution Utilities took a reasonable amount of time to secure the required subject matter expertise, settle on the platform, develop and issue the related Request for Proposals (RFPs), and assemble the necessary resources. As noted by the ATCO Distribution Utilities, the early efforts of Wipro and the ATCO Distribution Utilities started in 2015 and included pre-planning work toward the replacement of the CIS. Efforts were briefly paused in December 2017 to complete the implementation of Project Cirrus, and recommenced in mid-2018, which was the first year of PBR2.[239] Furthermore, the ATCO Distribution Utilities noted that Oracle's extended support was not undertaken as a means to delay Project Cirrus for any particular ATCO company. The extended support was not unique to ATCO Pipelines, was applied to all ATCO Oracle E-business uses, and was short term in nature. The Commission finds that given the integration between Oracle ERP and Oracle CCS, it was reasonable to implement Project Cirrus first, and limit technological changes potentially having an external impact on customers. The Commission also notes that the CIS business case had still

234 Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, paragraphs 138-144.
235 Proceeding 26615, Exhibit 26615-X0303, PDF page 7.
236 Proceeding 26615, Exhibit 26615-X0304, Stephens Consulting Evidence, PDF page 6.
237 Exhibit 26616-X0208-C, Stephens Consulting evidence, PDF page 19.
238 Exhibit 26616-X0081, ATCO Gas Prefiling of CIS Business Case, PDF pages 22-26; Proceeding 26615, Exhibit 26615-X0284, AE-AUC-2022FEB09-002(a) and Exhibit 26615-X0424-C, ATCO Electric rebuttal evidence, PDF page 50.
239 Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraph 302; Proceeding 26615, Exhibit 26615-X0424C, ATCO Electric rebuttal evidence, paragraph 143.

not been completed by the time Project Cirrus was implemented, thus it would have been difficult to align the timing of Project Cirrus and the CIS project.[240]

## Level of expenditures

263. The ATCO Distribution Utilities forecast a total capital spend of $180.1 million ($110 million for ATCO Gas, and $70.1 million for ATCO Electric) for the CIS Replacement project.[241] The following table shows the breakdown of total costs for each of the ATCO Distribution Utilities.

**Table 19. CIS Replacement project costs for ATCO Gas and ATCO Electric**

| Category | ATCO Gas | ATCO Electric | Total |
|---|---|---|---|
| | ($000) | | |
| Labour & expenses | 30,629 | 17,803 | 48,432 |
| Services | 50,175 | 27,257 | 77,432 |
| Computing | 20,133 | 5,176 | 25,309 |
| ESG | 3,371 | 2,620 | 5,991 |
| Contingency | 10,894 | 9,000 | |
| Oracle credit licence | (10,199) | (1,128) | (11,327) |
| Estimated credit from electricity | (2,694) | | (2,694) |
| Estimated credit to gas | | 6,265 | 6,265 |
| Allowance for funds used during construction | 8,586 | 3,118 | 11,704 |
| IT Common Matters total disallowance | (896) | | (896) |
| **Total replacement cost** | **109,999** | **70,111*** | **180,110** |

Source: Exhibit 26616-X0112.01, AG-UCA-2022FEB17-021(b); Proceeding 26615, Exhibit 26615-X0373, Updated Table 2.
*Note: The above table does not include the IT Common Matters prescribed pricing adjustment of $1.8 million.

## Calgary concerns

264. Calgary raised two concerns with the level of expenditures for the CIS replacement project.

265. First, Calgary was concerned that ATCO Gas and ATCO Electric's reliance on forecast cost per customer (CPC) of $76 and $235, respectively,[242] for their CIS project, as a measure of the reasonableness of expected CIS project costs, was flawed or that the measure was irrelevant. J. Stephens, on behalf of Calgary, noted that selected customer sizes in the TMG data are not comparable to the ATCO Distribution Utilities. J. Stephens also stated that the ATCO Distribution Utilities used a CAD to USD conversion, when portions of the project resources would likely be Canadian sourced at the CAD rate rather than a U.S.-equivalent skilled project resource being paid in USD.

266. J. Stephens raised a concern whether ATCO Electric is subsidizing the costs of the ATCO Gas portion of the CIS Replacement project, because ATCO Gas's CPC is much lower

[240] Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 298-299; Proceeding 26615, Exhibit 26615-X0424C, ATCO Electric rebuttal evidence, paragraph 141.
[241] Exhibit 26616-X0112.01, AG-UCA-2022FEB17-021(b); Proceeding 26615, Exhibit 26615-X024, ATCO Electric application, Appendix A, Sch. 4.1, line 13.
[242] Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraph 231; Proceeding 26615, Exhibit 26615-X0424-C, ATCO Electric rebuttal evidence, paragraph 116.

than ATCO Electric's CPC. J. Stephens also stated that ATCO Electric's implementation cost appears to be incorrect and "understates the true cost" per customer for ATCO Electric's customer base of 230,000, which J. Stephens' evidence shows is $319 per customer.[243]

267. Second, Doug Evanchuk, on behalf of Calgary, questioned whether the costs for members of the ATCO Distribution Utilities' CC&B team that worked on the CIS Replacement project were, in effect, double recovered through PBR revenues.[244]

268. With respect to Calgary's concerns regarding cost per customer, the Commission is not persuaded that CPC is an irrelevant measure of the reasonableness of the ATCO Distribution Utilities' expected costs for the CIS Replacement project. The Commission understands that the ATCO Distribution Utilities used CPC only as a guideline to assess the reasonableness of the expected costs of the CIS Replacement project.

269. ATCO Gas noted that the original TMG industry data identified 47 CPC comparators with an average CPC of $155.40 CAD, and that when seven comparators with less than one million customers were excluded, the average CPC is $156.29 CAD. Furthermore, ATCO Gas indicated that if the analysis is further limited to only those utilities serving from 1.0 million to 2.6 million customers, the average CPC is $156.26 CAD, an almost identical number. ATCO Electric also noted that its CPC of $235 CAD falls within the Tier 2 CPC range based on the industry data provided by TMG.[245]

270. With respect to Calgary's comment about USD to CAD conversion, the Commission finds that the ATCO Distribution Utilities' approach was reasonable. The ATCO Distribution Utilities indicated that many of the project resources are based outside of Canada and, as such, their pricing is based in U.S. dollars, and that they elected to sign contracts in Canadian dollars at the U.S. dollar equivalent.[246] The projects in the TMG data were therefore converted to Canadian dollars to enable direct comparisons with the ATCO Distribution Utilities' CPC.

271. The Commission also observes that J. Stephens' calculation of ATCO Electric's CPC of $319 per customer is not an accurate comparison to the CPC relied upon by the ATCO Distribution Utilities in the TMG data. As the ATCO Distribution Utilities noted, J. Stephens included the full program cost of the CIS Replacement project whereas TMG used CPC as a guideline intended to measure implementation costs only.[247] Further, while the size of the utility is a factor in calculating the CPC, the system requirements are the same regardless of the number of customers served by the distribution utility, and the application would still need to go through the same level of functional and technical design processes. Since ATCO Electric has a smaller

243 Exhibit 26616-X0208-C, Stephens Consulting evidence, PDF page 27; Exhibit 26616-X0208-C, Stephens Consulting evidence, PDF page 31.
244 Transcript, Volume 1 - Confidential, page 49.
245 Exhibit 26616-X0309-C, ATCO Electric and ATCO Gas Confidential Argument, PDF page 25.
246 Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 237-239.
247 Proceeding 26615, Exhibit 26615-X0424-C, ATCO Electric rebuttal evidence, Section 3.3.3, PDF page 44. ATCO Electric explained at paragraphs 114-115: "ATCO Electric's CPC is based on Stage 2 Expenditures and related contingency only, as these costs encompass the implementation and execution elements of the Program once the System Integrator is in place.… Overhead costs related to ES&G and IDC/AFUDC also are not included. Cost Sharing related to leveraged deliverables from the ATCO Gas Program and the Oracle Credit License also are excluded, …"

customer base, it would result in a higher CPC compared to utilities with a larger customer base, including ATCO Gas.[248]

272. In response to J. Stephens' concerns, ATCO Electric denied that it is subsidizing the costs of the ATCO Gas portion of the CIS Replacement project. ATCO Electric's costs are driven by its own unique requirements, such as customer types, integration requirements, metering complexities and billing requirements reflecting the Alberta deregulated model and Measurement Canada Compliance requirements.[249] The Commission is persuaded by this explanation and, in particular, finds it reasonable to expect that differences in the operational circumstances and functional requirements of ATCO Gas and ATCO Electric would result in a different CPC for each. In addition, the Commission finds neither compelling nor reasonable the proposition that the mere existence of differences in the CPC of affiliated utilities should, in and of itself, be considered evidence of a cross-subsidy between them.

273. With respect to Calgary's second concern, the Commission is not persuaded that double counting occurred. The ATCO Distribution Utilities were asked to provide a breakdown of the $17.8 million and $30.6 million of total labour and expenses for ATCO Electric and ATCO Gas, respectively.[250] In response, the ATCO Distribution Utilities filed undertakings[251] which noted that the majority of these positions were backfilled and that the backfilled costs and CIS costs were recorded separately; thus, there could be no double counting, nor double recovery.[252]

### Commission review of CIS replacement costs

274. For the reasons that follow, the Commission is persuaded that the ATCO Distribution Utilities' forecast CIS costs are reasonable.

275. The Commission is satisfied based on the evidence on the record that industry best practice (that is, a competitive procurement process) was followed to support the procurement of approximately 78 per cent of ATCO Electric's expected services costs and approximately 74 per cent of ATCO Gas's expected services costs. The ATCO Distribution Utilities filed statements of work and information pertaining to the RFP process to support these CIS replacement costs.[253] This competitive process involved developing a scorecard, with guidance from TMG, that contained criteria with respect to pricing, staffing, contract terms, industry qualifications, proposed solutions, timeline for implementation, oral presentations and references. Notwithstanding that the scorecard emphasized that price is not the only consideration for a project of this nature, the ATCO Distribution Utilities noted that they still elected to weigh the Commercial – Pricing category more heavily than recommended by TMG.[254]

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248 The ATCO Gas customer base is 1,260,000, compared to the ATCO Electric customer base of 230,582 (Exhibit 26616-X0233, ATCO Gas rebuttal evidence, Table 19 at paragraph 231; Proceeding 26615, Exhibit 26615-X0424-C, ATCO Electric rebuttal evidence, paragraph 116).

249 Proceeding 26615, Exhibit 26615-X0424-C, ATCO Electric rebuttal evidence, paragraphs 118, 119 and 130.

250 Transcript, Volume 1 - Confidential, page 51.

251 Exhibit 26616-X0296, ATCO Gas Confidential Undertaking 6; Exhibit 26616-X0297, ATCO Gas Confidential Undertaking 7.

252 Exhibit 26616-X0309-C, ATCO Electric and ATCO Gas final argument, paragraph 107.

253 Exhibit 26616-X0309-C, ATCO Electric and ATCO Gas final argument, paragraphs 100-102.

254 Exhibit 26616-X0233, ATCO Gas rebuttal evidence, paragraphs 243-246; Proceeding 26615, Exhibit 26615-X0424-C, ATCO Electric rebuttal evidence, paragraph 127.

276. Accordingly, the Commission finds that the costs incurred or forecast to be incurred under the competitive procurement processes used by the ATCO Distribution Utilities and reviewed by TMG are reasonable. The Commission, however, must also ensure that the remaining 22 and 26 per cent of ATCO Electric and ATCO Gas CIS project costs are reasonable.

277. The majority of the remaining costs for the ATCO Distribution Utilities are direct labour. The ATCO Distribution Utilities provided a breakdown of their expected labour costs, which includes a mix of in-house employees and contractors, as part of their business cases.[255] In the data provided, the total labour costs were broken down as follows:

**Table 20. Total forecast direct labour cost for CIS Replacement project**

| | ATCO Gas | ATCO Electric |
|---|---|---|
| Total fully burdened direct labour as per business case ($000)* | $21,759 | $14,087 |
| Hours | 204,779 | 136,862 |

Source: Exhibit 26616-X0081, ATCO Gas CIS Business Case, Appendix B, Table 2; Proceeding 26615, Exhibit 26615-X0177, Appendix B, Attachment 1, Table 2, PDF page 293.
*Note: Exhibit 26616-X0081, ATCO Gas CIS Business Case, Appendix B, PDF pages 58, 69-70; Proceeding 26615, Exhibit 26615-X0177, Appendix B, PDF pages 282, 292-293.

278. The business cases provided in respect of this project indicated that approximately 43 per cent of the direct labour FTEs for ATCO Gas, and 38 per cent of the direct labour FTEs for ATCO Electric, were forecast to be attributable to contractors.[256] In this proceeding, there was no information provided on (i) how much of the direct labour cost was attributable to contractors; and (ii) whether the direct labour contractor resources (FTEs) were competitively procured.

279. The ATCO Distribution Utilities bear the onus of demonstrating that the inclusion of the direct labour costs in forecast revenue requirement results in just and reasonable rates. Given that the ATCO Distribution Utilities did not clearly indicate whether a competitive procurement process was used to obtain the contractor resources which are part of the noted Direct Labour costs, the Commission reviewed the supporting evidence to determine the reasonableness of these forecast costs. In other words, without clear evidence of a full competitive procurement process, these costs are at greater risk of disallowance because it is more difficult for the Commission to assess whether they are reasonable.

280. Notwithstanding, the Commission has reviewed the record and has concluded, on a balance of probabilities, that the contractor portion of the expected direct labour costs for the CIS Replacement project are reasonable. Based on the data set out in Table 20 above, ATCO Gas has a forecast average fully burdened labour cost of $106.26 per hour, and ATCO Electric a forecast average fully burdened labour cost of $102.93 per hour. The Commission is satisfied that the number of hours and resulting total fully burdened labour costs are reasonable for a project of this nature, given the mix of in-house employees and contractors and the skillsets required to implement the project. In making this finding, the Commission has also relied on the fact that the resource plans for ATCO Distribution Utilities were reviewed and validated by TMG, and align

[255] Exhibit 26616-X0081, ATCO Gas CIS Business Case, Appendix B, Table 2; Proceeding 26615, Exhibit 26615-X0177, Appendix B, Attachment 1, Table 2, PDF page 293.
[256] Exhibit 26616-X0081, ATCO Gas CIS Business Case, Appendix B, Table 2; Proceeding 26615, Exhibit 26615-X0177, Appendix B, Attachment 1, Table 2, PDF page 293.

with successful CIS implementations that TMG has been involved with in the past.[257] TMG is product and vendor agnostic and has supported over 400 utility CIS implementations in Canada and the U.S.[258] It is also noteworthy that no party specifically took issue with the contractor portion of the direct labour costs associated with the project.

281. Finally, ATCO Electric explained that, as the managed service provider at the time of the CIS Replacement project, Wipro was required to perform work on the CIS project. In preparing the CIS Replacement project business case, ATCO Electric forecast Wipro services costs of $6.7 million using the Wipro rates set out in the Wipro Master Services Agreement (Wipro MSA). As such, ATCO Electric identified that a $1.8 million reduction to the cost of the Wipro services involved in the CIS Replacement project was required to comply with the pricing directed in Decision 20514-D02-2019[259] (the IT Common Matters decision). ATCO Electric confirmed that actual costs charged to the project for these services performed by Wipro used the prescribed IT Common Matters rates. ATCO Electric proposed to make the necessary adjustment to the approved 2023 revenue requirement at the time of the compliance filing.[260] The Commission agrees and directs ATCO Electric to remove $1.8 million in capital additions for this project in its compliance filing.

## 7.3 Apex 2023 forecast capital additions

282. To arrive at its requested overall 2023 capital forecast, Apex used a hybrid approach, which consisted of a combination of mechanistic forecasts for recurring programs and non-mechanistic forecasts for non-recurring or new programs. The mechanistic forecasts were based on a three-year indexed average of Apex’s 2018 to 2020 capital additions. The non-mechanistic forecasts were supported by more detailed analysis and business cases.[261]

283. Consistent with Decision 26354-D01-2021,[262] Apex categorized its capital program as either recurring or non-recurring. Recurring capital programs have predictable stable costs and similar drivers over time and are expected to recur in future years. Non-recurring capital programs are either new, one-off projects or projects that may occur at unpredictable intervals in the future.[263]

284. Apex forecast its capital additions as shown in the table below.

**Table 21. Apex 2020-2023 actual and forecast capital additions**

| Capital program | 2020 Actual | 2021 Forecast | 2022 Forecast | 2023 Forecast | Forecast methodology |
|---|---|---|---|---|---|
| | ($000) | | | | |
| Growth | 6,285 | 7,241 | 7,487 | 8,598 | Mechanistic |
| System Sustainment | 1,922 | 3,220 | 3,329 | 3,458 | Mechanistic |

257 Exhibit 26616-X0081, ATCO Gas CIS Business Case, Appendix A, PDF page 58; Proceeding 26615, Exhibit 26615-X0177, PDF page 282.
258 Exhibit 26616-X0081, ATCO Gas CIS Business Case, PDF page 8.
259 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.
260 Proceeding 26615, Exhibit 26615-X0284, AE-AUC-2022FEB09-002(b-c), and Exhibit 26615-X0373, ATCO Electric Additional CIS Project Information, PDF pages 4-5.
261 Exhibit 26616-X0023, Apex application, PDF page 29, paragraphs 77-79.
262 Decision 26354-D01-2021, paragraph 30(iii)-(iv).
263 Exhibit 26616-X0023, Apex application, PDF page 28, paragraph 74.

| Capital program | 2020 Actual | 2021 Forecast | 2022 Forecast | 2023 Forecast | Forecast methodology |
|---|---|---|---|---|---|
| | ($000) | | | | |
| Infrastructure Renewal | 25,480 | 22,746 | 25,517 | 24,427 | Mechanistic |
| Metering | 1,441 | 1,453 | 1,503 | 1,561 | Mechanistic |
| General Support | 5,637 | 6,247 | 6,459 | 6,709 | Mechanistic |
| Gas Supply | 853 | - | - | 3,550 | Non-mechanistic |
| NOVA Gas Transmission Ltd. (NGTL) Abandonment Response | 243 | - | - | 3,267 | Non-mechanistic |
| CIS | | 18,200 [Note 1] | - | - | Actual costs |
| NGSSC | - | - | - | 5,667 | Non-mechanistic |
| **Total** | **41,895** | **59,107** | **42,294** | **57,236** | |

Source: Exhibit 26616-X0197, Appendix 2, Updated,[264] Apex Commission Template, WP-002 Additions.
Note 1: CIS project 2021 actual capital additions from Exhibit 26616-X0196, Appendix 1 – 2021 OM and Capital Variances, Schedule 2.

### 7.3.1 Recurring capital (mechanistic approach)

285. As noted earlier, Apex forecast the 2023 costs for all of its recurring programs using the mechanistic approach.

286. The Commission approves the use of the mechanistic approach by Apex to develop the forecasts for capital additions that were characterized by predictable costs and similar drivers over time. In the Commission's view, generally, the capital additions in this category did not require further detail or support because the forecast costs were aligned with Apex's historical spending, which was undertaken while operating under the incentives of PBR. Such forecasts were also supported by way of variance explanations at the appropriate level, as and when required. The Commission finds the costs underlying forecasts to be less susceptible to volatility in 2023, and beyond, given the predictable pattern in the past. Furthermore, the Commission determined in Section 5.1 that for costs forecast using a mechanistic approach, the Commission is satisfied that the use of the 2018-2020 average, escalated by indexes approved in Section 5.2, results in a 2023 forecast that is reasonably reflective of the efficiencies achieved during the PBR2 term.

287. The Commission finds that the 2023 forecast costs for those programs that were forecast mechanistically are reasonable and approves them as filed, subject to using the escalators approved in Section 5.2. Accordingly, the Commission directs Apex to provide updated amounts in the compliance filing.

### 7.3.2 Non-recurring or new capital (non-mechanistic approach)

288. The Barrhead, Westlock, Morinville (BWM) gas supply, NGTL abandonment response and NGSSC systems replacement projects that were forecast using a non-mechanistic approach are addressed in the following sections.

264 Apex updated Appendix 2 to reflect the withdrawal of the hydrogen projects from its application as directed in Exhibit 26616-X0102, AUC letter - Preliminary jurisdictional issues - hydrogen projects.

#### 7.3.2.1 Barrhead, Westlock, Morinville gas supply

289. In its application, Apex explained that gas supply for the BWM area relies on contracted transportation of gas through a Tidewater Midstream and Infrastructure Ltd. (Tidewater) pipeline system. Apex also explained that it understands that Tidewater moves natural gas liquids (NGL) to its processing facilities in Fort Saskatchewan through the same pipeline system. While Apex has been able to manage the amounts of NGL, greater concentrations of NGL could risk the delivery of safe and reliable service to its customers. Apex also asserted that there is an associated risk that the transportation agreement with Tidewater can be cancelled by Tidewater on one-year's notice, which is less than the time it would take for Apex to construct a bypass system.

290. In addition to the supply risk, Apex must also pay variable transportation costs of approximately $0.3 million per year for gas transported through Tidewater's system. These costs are incremental to the fixed charges to source gas from ATCO Pipelines and NGTL. Apex expects significant natural gas demand growth in the area. As a result, in its application Apex has proposed the construction of a gas bypass system.[265]

291. As part of the construction of a gas bypass system, Apex plans to negotiate a long-term agreement with Tidewater to change the notice period required to cancel the transportation agreement, from one year to three years. Phase 1 of this project involves Apex beginning construction of strategic BWM system upgrades that would provide a backup gas supply to approximately 800 customers and align with the ongoing non-certified polyethylene (non-certified PE or NCPE) replacement program. Apex planned to complete the upgrades in 2023 at an estimated cost of $3.55 million.[266] Apex explained that Phase 1 would also upgrade one station and replace 17 km of the 32 km of proposed medium-pressure PE pipe that has already been identified for replacement under Apex's non-certified PE replacement program. Apex estimates a reduction in transportation costs of $30,000 a year as a result of the upgrades in Phase 1.[267]

292. Apex indicated that Phase 2 of the project would occur after 2023 at a cost of $16.72 million and would take three years to complete. Apex explained that this phase would be deferred until a revised agreement with Tidewater with a longer cancellation notice period is completed. If such an agreement cannot be reached, then Phase 2 would proceed as planned or be re-evaluated based upon the results of any renegotiation with Tidewater. In the application, Apex only applied for Phase 1 of the project.[268]

293. In their evidence, both the UCA and the CCA questioned the timing of the project. The UCA stated that Apex was aware in 2015 when Tidewater acquired the pipeline from ATCO Energy Solutions Inc. of the concerns relating to Tidewater's plans to transport liquids-rich gas. The UCA submitted that Apex decided to continue with the contract and not spend any capital on a bypass during PBR and chose to defer the project until after the PBR2 term.[269] In its rebuttal evidence, Apex stated that since 2015 it has been monitoring the amounts of liquids in the system and has been updating the project scope plans as required. The construction of portions of

265 Exhibit 26616-X0023, Apex application, appendix 3.1, PDF page 124.
266 Exhibit 26616-X0023, Apex application, appendix 3.1, PDF page 125.
267 Exhibit 26616-X0023, Apex application, Appendix 3.1, PDF pages 137-138.
268 Exhibit 26616-X0023, Apex application, Appendix 3.1, PDF pages 132-133.
269 Exhibit 26616-X0203, UCA evidence, PDF pages 43-44.

the bypass in 2023 aligns with other work in the area and is expected to benefit from synergies and efficiencies gained.

294. At the hearing, Apex's witnesses were questioned by Commission counsel about whether Apex would proceed with Phase 1 of the project in 2023 regardless of how the Commission rules in this proceeding. G. Feltham responded that based on the supply risk in the BWM area and its obligation to serve, absent any new information coming to light, Apex has every intention of completing the work regardless of what the Commission rules.[270] Further, Imad Khaled explained that regardless of the negotiations with Tidewater, purely from a security of supply perspective and the risk of liquids in the system, Apex accepts that the bypass will be needed at some point. He added that since the risk came to Apex's attention in 2016, it has been looking at opportunities to capitalize on efficiencies to align with other work in the area, and this opportunity presented itself in 2023.[271]

295. The Commission is persuaded that there are risks to Apex's distribution system if Tidewater increases the concentration of NGL, that this risk could materialize without any notice to Apex or any ability on its part to control, and could have a potentially detrimental effect on Apex's obligation to serve its customers. While the Commission acknowledges the UCA and the CCA concerns regarding the timing of this project, the Commission is satisfied that Apex has taken reasonable measures by monitoring the amounts of liquids-rich gas in the system. The Commission is also satisfied that constructing Phase 1 of the bypass system in 2023 is reasonable as it aligns with other work in the area, including the replacement of a portion of the pipe that was already designated to be replaced as part of Apex's non-certified PE replacement program. As a result, the Commission approves the inclusion of $3.55 million of capital additions for the BWM gas supply project in Apex's 2023 forecast revenue requirement.

#### 7.3.2.2 Athabasca gas supply

296. In its application, Apex stated that NGTL identified certain assets for deactivation, decommissioning and abandonment that would impact Apex and its customers in 2023. NGTL notified Apex that it plans to cease service on the September Lake and Island Lake laterals in 2024.[272] Apex receives service on these laterals under the terms of a commercial agreement with NGTL. Apex indicated that the September Lake and Island Lake laterals are the sole source of natural gas to the Athabasca area and the laterals provide natural gas supply to multiple locations. Apex stated that the termination of service on these facilities would affect approximately 3,600 customers in the town of Athabasca and the surrounding area.[273]

297. In the business case for this project, Apex stated that there were three possible scenarios for how it might deal with the closing of NGTL's September Lake and Island Lake laterals. The first scenario was to maintain the status quo, which Apex stated was not possible because it received notice from NGTL that the laterals would be decommissioned, and Apex has an obligation to serve its customers. The second scenario was to purchase the September Lake and Island Lake laterals. Apex stated that it is currently in discussions with NGTL regarding the purchase of the infrastructure. However, at the time of filing, Apex did not have enough information on the status or costs of the assets to properly evaluate this alternative. As a result,

270 Transcript, Volume 3, page 216, lines 8-22.
271 Transcript, Volume 3, page 217, lines 4-18.
272 Exhibit 26616-X0023, Apex application, paragraph 139.
273 Exhibit 26616-X0023, Apex application, paragraph 140.

this alternative was pursued concurrently with the third and final scenario, which was for Apex to construct a new gas supply system. This scenario leverages Apex's existing infrastructure and includes construction of high- and medium-pressure pipelines, a station facility relocation and other modifications to various station facilities.[274]

298. As part of its application, Apex forecast $3.27 million in capital additions related to this project in 2023.[275] This forecast is based on Apex committing to the third scenario described above; that is, construction of new infrastructure.[276]

299. In his evidence for the UCA, R. Bell stated that it was premature to include expenditures related to this project in customer rates due to the ongoing discussions between NGTL and Apex regarding the purchase of the NGTL assets.[277]

300. During argument, NGTL supported approval of Apex's expenditures for this project. NGTL noted that it is in negotiations with Apex regarding the closure of the laterals mentioned above and that it would be prudent for the Commission to approve the applied-for expenditures for this project given NGTL's intention to discontinue service. However, NGTL also explained that there are a number of uncertainties associated with this project.[278]

301. NGTL noted that it has not yet filed an application for abandonment with the Canada Energy Regulator (CER), but had provided notice of retirement under its commercial agreement with Apex. NGTL indicated that it would not have issued the notice of retirement to Apex if there were any doubt about NGTL's intention to retire the utility tap facility (referred to as TAPs), contrary to the UCA's submission about Apex's application being premature. Apex explained that it has pre-emptively filed an objection with the CER about the NGTL retirement and that it will decide whether to intervene in a future CER proceeding dealing with the abandonment based on the outcome of negotiations between itself and NGTL on how to maintain gas supply.[279] An outcome of this complaint and negotiation process could be that NGTL files a future application with the CER for another commercial solution to the concerns previously raised by Apex.[280]

302. The Commission finds there is insufficient evidence on the record of this proceeding to approve Apex's proposal. The Commission accepts that Apex may need to expend funds to purchase the laterals or, if NGTL proceeds to abandon the laterals and obtains CER approval to do so, to construct a new system. However, the timing of such purchases or construction and the amount of required funding associated with either option are uncertain at this time. In fact, neither the purchase of the laterals and associated infrastructure nor the construction of alternate infrastructure by Apex appears to be inevitable based on the record of this proceeding. NGTL specifically acknowledged that another commercial solution may be possible where NGTL neither abandons the laterals nor sells them to Apex. In this context, the Commission finds that there is too much uncertainty associated with the potential abandonment by NGTL of the

274 Exhibit 26616-X0023, Apex application, Appendix 3.2, PDF page 142, paragraphs 2-5.
275 Exhibit 26616-X0023, Apex application, paragraph 141.
276 Exhibit 26616-X0023, Apex application, Appendix 3.2, PDF page 148, paragraph 20.
277 Exhibit 26616-X0203, UCA evidence, PDF page 41.
278 Transcript, Volume 5, page 524.
279 Exhibit 26616-X0311, Apex final argument, PDF page 10.
280 Transcript, Volume 5, page 524.

September Lake and Island Lake laterals and that it is therefore premature to approve Apex's applied-for funding for this project.

303. The Commission directs Apex to remove the proposed $3.27 million of capital additions from its 2023 forecast revenue requirement in the compliance filing to this decision.

### 7.3.2.3 Natural Gas Settlement System Code Systems replacement

304. Apex forecast $5.67 million in capital additions to replace its Load Profiling and Settlement (LPS) system and its Nomination, Imbalance & Settlement Information System (NISIS). These systems are used to fulfil Apex's gas settlement function as mandated under Rule 028: *Natural Gas Settlement System Code Rules* (NGSSC).[281] This replacement is required as vendor support for both the LPS system and the NISIS is ending.

305. Apex uses an Oracle LPS system and a customer-developed web application for its NISIS. The two systems are tied together through the use of common database tables.[282] The need to upgrade the LPS system is driven by Oracle's announcement that it will no longer provide support for the application after March 2022.[283] Microsoft also announced that it will retire the software framework used by the NISIS in April 2022, due to cybersecurity constraints.[284] Although the NISIS could be updated to a new framework, the shared databases between the LPS system and NISIS mean that the NISIS would also need to be significantly modified to align with the replacement LPS system.[285] As a result, Apex has proposed a joint replacement as the most cost-effective option.

306. The CCA raised concerns about whether Oracle will support the LPS system until 2023, rather than 2022 as stated by Apex, which would allow Apex to defer the replacement project until 2024.[286] After reviewing the evidence provided by Apex, the Commission is satisfied that support will cease in 2022,[287] necessitating a replacement in 2023.

307. The forecast for this replacement is based on initial estimates from two vendors.[288] Apex estimated that replacement of the LPS will cost $4.6 million, and replacement of the NISIS will cost $1.1 million. Apex will be completing a formal RFP to finalize vendor and product selection in 2022. Apex stated that it expects this upgrade to result in minimal retailer effort and cost. Apex will be providing retailers with documentation and training to support the transition to the new system.[289]

281 Exhibit 26616-X0023, Apex application, Appendix 3.4 NGSSC Systems Replacement Business Case, PDF page 174, paragraph 1.
282 Exhibit 26616-X0023, Apex application, Appendix 3.4 NGSSC Systems Replacement Business Case, PDF pages 175-176, paragraph 6.
283 Exhibit 26616-X0023, Apex application, Appendix 3.4 NGSSC Systems Replacement Business Case, paragraph 6.
284 Exhibit 26616-X0106, AUI-AUC-2022FEB17-005(c).
285 Exhibit 26616-X0106, AUI-AUC-2022FEB17-005(c).
286 Exhibit 26616-X0205.03, CCA evidence of J. Thygesen, paragraph 146.
287 Exhibit 26616-X0231, Apex rebuttal evidence, paragraph 66.
288 Exhibit 26616-X0023, Apex application, Appendix 3.4 NGSSC Systems Replacement Business Case, PDF page 178, paragraph 15.
289 Exhibit 26616-X0106, AUI-AUC-2022FEB17-005(d).

308. The Commission finds Apex's proposal to upgrade both its LPS system and NISIS to be reasonable, given that Microsoft and Oracle will no longer be offering support for these programs. The Commission therefore approves the forecast of $5.67 million.

309. Apex proposed deferral account treatment for the costs of this program (both capital and O&M), in alignment with how settlement costs have been handled during the current PBR term.[290] However, the Commission notes that the reasons why this program was granted deferral account treatment no longer apply. In Decision 2012-311, the Commission granted Apex a Y factor treatment for an NGSSC project because the project was a result of a Commission direction.[291] That project has since been completed.

310. The 2023 forecast operating and capital costs for the NGSSC program are driven by the vendor decisions to cease support for the systems used by the current NGSSC. Since the project being applied for in 2023 is based on different drivers than what was previously approved for Y factor treatment in Decision 2012-311, the Commission is not persuaded that this project should continue to receive deferral account treatment. Further, in the Commission's view, Apex is well positioned to manage these costs as NGSSC has been a part of its business for the last decade. Accordingly, the Commission denies Apex's use of a deferral account for this program.

## 8 IT costs – ATCO Gas and ATCO Electric

311. This decision addresses the applications for IT O&M costs for both ATCO Electric (Proceeding 26615) and ATCO Gas. In their applications, the ATCO Distribution Utilities sought approval of costs for IT O&M. Because these applications raised similar issues, the Commission determined that oral evidence and argument on ATCO Distribution Utilities' IT matters would be heard in Proceeding 26616.[292] Written evidence regarding ATCO Electric's IT costs was incorporated into the record of Proceeding 26616.[293]

312. Based on the record of this proceeding, the Commission is not persuaded that ATCO Electric's 2023 IT O&M forecast of $17,688,000 (which includes $8,187,000 in passthrough costs[294]) and ATCO Gas's 2023 IT forecast of $30,946,000 (which includes $14,534,000 in passthrough costs)[295] are reasonable. The Commission is not satisfied that the ATCO Distribution Utilities have met their onus to justify their 2023 forecast IT costs because they: (i) did not conduct a competitive procurement process for IT services after terminating the 10-year Wipro

290 Exhibit 26616-X0023, Apex application, paragraph 19.
291 Decision 2012-311: Errata to Decision 2012-311 2010-2012, General Rate Application – Phase I Compliance Filing Pursuant to Decision 2012-091, Proceeding 1921, Application 1608512, December 5, 2012, paragraph 172.
292 Proceeding 26615, Exhibit 26615-X0426, AUC letter - Process and scope for oral questioning and oral argument and reply.
293 Exhibit 26616-X0239, AUC letter - Process and scope for oral questioning and oral argument and reply.
294 Passthrough cost are costs where no overhead, administrative expense, or profit is added (e.g., software and subscriptions, IT licensing and maintenance).
295 Exhibit 26616-X0018, ATCO Gas application, PDF page 36, Table 11, and Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, PDF page 36, Table 11. For ATCO Electric, the IT common matters 2023 forecast was revised to $15,742,000 because of a calculation error.

MSA[296] between the ATCO Utilities[297] and Wipro Solutions Canada Limited; (ii) failed to provide any relevant benchmarks for their IT costs; and (iii) did not provide sufficient evidence to establish that the new IT rates and costs under an MSA with IBM/Kyndryl (IBM/Kyndryl MSA) were reasonable.

313. For the reasons set out below, the Commission finds that reductions of 15 per cent to the ATCO Distribution Utilities' 2023 IT managed services forecast costs under the IBM/Kyndryl MSA are warranted and appropriate. This 15 per cent reduction results in a disallowance of approximately $1.43 million for ATCO Electric and $2.49 million for ATCO Gas in 2023.

314. The examination of the IBM/Kyndryl MSA was a complex and significant part of this proceeding. The issues intersected and overlapped with those addressed in a previous Commission decision known as the IT Common Matters decision, where the ATCO Utilities' previous Wipro MSA was closely examined, and costs were disallowed. In the sections that follow, the Commission first outlines the requests made by the ATCO Distribution Utilities in this proceeding. It then provides a brief summary of the IT Common Matters decision. The evidence provided by the ATCO Distribution Utilities in this proceeding is then outlined, followed by submissions from Calgary and the UCA. The Commission concludes with its reasons for declining to approve a portion of the ATCO Distribution Utilities' forecast IT managed services costs related to the IBM/Kyndryl MSA.

## 8.1 Background

315. In their respective applications, the ATCO Distribution Utilities informed the Commission that they were seeking recovery of IT costs associated with a new MSA with IBM/Kyndryl.[298] On December 31, 2020, ATCO Technology Management Ltd. (ATML) entered into an MSA with IBM/Kyndryl to provide IT managed services to ATCO effective July 31, 2021, to April 30, 2025.[299] Shortly afterward, the ATCO Distribution Utilities terminated their 10-year Wipro MSAs, which were previously set to end December 31, 2024. The Commission-approved rates for IT managed services procured pursuant to the Wipro MSAs were set in accordance with the IT Common Matters decision.

316. The following two tables compare the forecast costs for ATCO Gas and ATCO Electric using rates under the new IBM/Kyndryl MSA[300] and the IT rates set out in the IT Common Matters decision:[301]

296 While the ATCO Utilities signed separate MSAs with Wipro, these agreements tracked an overall Wipro MSA signed on behalf of multiple ATCO entities. The Wipro MSAs signed by the ATCO Utilities is referred to in this decision as the Wipro MSA.

297 The ATCO Utilities include ATCO Electric Transmission and ATCO Electric Distribution, divisions of ATCO Electric Ltd.; and ATCO Gas and ATCO Pipelines, divisions of ATCO Gas and Pipelines Ltd.

298 Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, PDF pages 35-36, and Exhibit 26616-X0018, ATCO Gas application, PDF page 35.

299 Exhibit 26616-X0018, ATCO Gas application, PDF page 35, and Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, PDF page 35.

300 Proceeding 26615, Exhibit 26615-X0120-C, AED Summary to AUC Request on IT Costs, and Exhibit 26616-X0051-C, Amending Agreement (No. 6) Exhibit P.1-Pricing Forms Regulated, Common Unit Rates.

301 Exhibit 26616-X0018, ATCO Gas application, PDF page 36, Table 11, and Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, PDF page 36, Table 11. Exhibit 26615-X0234, AE-AUC-2022JAN21-003(a): for ATCO Electric, the IT common matters 2023 forecast was revised to $15,742,000 because of a calculation error.

**Table 22. ATCO Gas IT O&M costs – IBM/Kyndryl vs. IT Common Matters rates**

| | IBM/Kyndryl | | | IT Common Matters | | |
|---|---|---|---|---|---|---|
| | 2021 Forecast | 2022 Forecast | 2023 Forecast | 2021 Forecast | 2022 Forecast | 2023 Forecast |
| | ($000) | | | | | |
| Managed Services | 18,979 | 18,305 | 16,592 | 20,426 | 19,091 | 13,463 |
| Passthroughs | 8,543 | 11,714 | 14,354 | 8,543 | 11,714 | 14,354 |
| **Total costs** | **27,522** | **30,018** | **30,946** | **28,969** | **30,805** | **27,817** |

**Table 23. ATCO Electric IT O&M costs – IBM/Kyndryl vs. IT Common Matters rates**

| | IBM/Kyndryl | | | IT Common Matters | | |
|---|---|---|---|---|---|---|
| | 2021 Forecast | 2022 Forecast | 2023 Forecast | 2021 Forecast | 2022 Forecast | 2023 Forecast |
| | ($000) | | | | | |
| Managed Services | 10,146 | 10,489 | 9,501 | 8,575 | 7,866 | 7,555 |
| Passthroughs | 6,794 | 7,555 | 8,187 | 6,794 | 7,555 | 8,187 |
| **Total costs** | **16,940** | **18,043** | **17,688** | **15,369** | **15,421** | **15,742** |

## 8.2 The IT Common Matters decision

317. The ATCO Distribution Utilities' applications referenced the Commission's IT Common Matters decision.[302]

318. Prior to December 31, 2014, the ATCO Utilities obtained IT services from ATCO I-Tek Inc., an unregulated affiliate company owned by Canadian Utilities Limited (CU), which also owns the ATCO Utilities.[303] ATCO Ltd. is the parent of CU.[304] On or about August 15, 2014, ATCO sold ATCO I-Tek to Wipro for approximately $204 million. Concurrent with the sale, ATCO contracted with Wipro for IT services and entered into an [redacted] with Wipro [redacted]). On August 15, 2014, each of the ATCO Utilities[305] entered into 10-year MSAs with Wipro for the provision of IT services commencing [redacted][306]

319. In the IT Common Matters decision, the Commission examined the prices contained in the Wipro MSAs with the ATCO Utilities. The Commission found that the ATCO Utilities failed to demonstrate that the IT pricing would result in just and reasonable rates, and ordered adjustments to IT costs that the ATCO Utilities were allowed to recover from customers. Specifically, in the first year of the Wipro MSAs, the Commission required that pricing be

302 Decision 20514-D02-2019.
303 Decision 20514-D02-2019, paragraph 24.
304 In the IT Common Matters proceeding, the ATCO Utilities referred to ATCO Ltd. and CU collectively as ATCO or ATCO Ltd. The Commission therefore refers to ATCO Ltd. and CU collectively as ATCO throughout the remainder of this decision for consistency. Both ATCO Ltd. and CU are an "owner of a public utility" within the meaning of Section l(h) of the *Public Utilities Act*.
305 ATCO Electric Transmission and ATCO Electric Distribution, divisions of ATCO Electric Ltd.; and ATCO Gas and ATCO Pipelines, divisions of ATCO Gas and Pipelines Ltd.
306 Decision 20514-D02-2019, paragraph 25.

reduced by 13 per cent. In years 2 through 10 of the Wipro MSAs, the Commission imposed a glide path[307] of 4.61 per cent, meaning that costs would decline by that percentage every year.[308]

320. The reasoning underlying the IT Common Matters decision is complex, but can be briefly summarized as follows. As noted above, prior to 2014, the ATCO Utilities received IT services from I-Tek, which was owned by CU. CU decided to move to an external IT provider, but the sale of ATCO I-Tek was an integral part of the transaction; that is, any company that wanted to provide IT services to any ATCO companies (by signing an MSA) also had to buy ATCO I-Tek.[309]

321. The Commission found that this commercial structure (I-Tek sale tied to MSA for IT services) meant that there were fewer firms competing, because companies that did not want to purchase I-Tek dropped out of the bidding process.[310] This meant that the bids for the MSA for IT services were higher, and the Commission found there was a direct link between the I-Tek price and the level of IT service prices in the bids, with the bids for MSA IT services going up or down with the prices offered for ATCO I-Tek.[311] As noted above, Wipro ultimately paid $204 million for I-Tek.

322. [redacted][312] [redacted][313]

323. [redacted][314]

### 8.3 ATCO Distribution Utilities' evidence regarding the move to IBM/Kyndryl

324. Over the course of proceedings 26615 and 26616, the ATCO Distribution Utilities provided a number of different explanations for the termination of the Wipro MSAs and the move to the IBM/Kyndryl MSA.

325. At the outset, ATCO Electric's application indicated that the IBM agreement was put in place "to immediately address the changing needs, including the need to mitigate the adverse

307 A glide path is a reduction in IT pricing or rates on an annual basis over the life of the agreement which often varies by IT service. Productivity improvements, automation and offshoring are examples of potential or anticipated future cost savings that can be built into a glide path.
308 Decision 20514-D02-2019, PDF page 5.
309 Decision 20514-D02-2019, paragraph 115.
310 Decision 20514-D02-2019, paragraphs 116-117.
311 Decision 20514-D02-2019, paragraph 263.
312 Decision 20514-D02-2019, paragraph 239.
313 Decision 25014-D02-2019, paragraph 259.
314 Decision 20514-D02-2019, paragraph 264.

effects of Decision 20514-D02-2019," i.e., the IT Common Matters decision.[315] ATCO Gas provided the same explanation in its application.[316]

326. The ATCO Distribution Utilities further submitted that under PBR, they were incented to find efficiencies, both by driving down costs and transforming the way they provided services to customers. They were incented "to reduce costs associated with IT services under the Wipro contract and mitigate the cost disallowance arising from Decision 20514-D02-2019 which directed the substitution of approved IT Common Matter rates in place of the rates negotiated with Wipro." Both utilities asserted that they were highly motivated to secure services for the lowest cost, and that the IBM/Kyndryl MSA fully reflected those incentives and efficiencies.[317] In its November 15, 2022, filing, ATCO Electric advised that it had "rearranged its affairs in such a way as to ensure service standards continue to be met while minimizing its costs."[318] In its December 15, 2021, filing, ATCO Gas expanded on this, noting that it rearranged its affairs "to ensure **service standards continue to be met while choosing a service provider that could reduce cost and also transform IT services to meet customer, legislative and industry needs.** [emphasis added]"[319]

327. In response to initial Commission questions following the filing of the applications, the ATCO Distribution Utilities emphasized transformation and the changing business environment, increased remote work capabilities due to the pandemic, the shift to cloud-based solutions, and security as factors that affect ATCO's business requirements. They noted that different IT solutions are necessary to meet these requirements.[320] The ATCO Distribution Utilities also explained that [redacted].[321] The cost comparisons for the IBM/Kyndryl MSA, the IT Common Matters decision, and the [redacted] are set out below:

**Table 24. The ATCO Distribution Utilities 2023 managed services forecast**

| | IBM/Kyndryl | IT Common Matters | [redacted] |
|---|---|---|---|
| | ($000) | | |
| ATCO Electric | $9,501 | $7,555 | [redacted] |
| ATCO Gas | $16,592 | $13,463 | [redacted] |

Source: ATCO Electric, Proceeding 26615, Exhibit 26615-X0110-C, PDF page 5. ATCO Gas, Exhibit 26616-X0041-C, PDF page 5.

315 Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, paragraph 107.
316 Exhibit 26616-X0018, ATCO Gas application, paragraph 106.
317 Exhibit 26616-X0018, ATCO Gas application, paragraph 110, and Proceeding 26615, Exhibit 26615-X0023, paragraph 110.
318 Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, paragraph 113.
319 Exhibit 26616-X0018, ATCO Gas application, PDF pages 37-38, paragraph 114.
320 Proceeding 26615, Exhibit 26615-X0110-C, AED Summary to AUC Requests on IT Costs, PDF page 2. Exhibit 26616-X0041-C, ATCO Gas Summary to AUC Request on IT Costs, PDF page 2.
321 Proceeding 26615, Exhibit 26615-X110-C, AED Summary to AUC Requests on IT Costs, PDF page 5. Exhibit 26616-X0041-C, ATCO Gas Summary to AUC Request on IT Costs, PDF page 5.

328. Both ATCO Electric and ATCO Gas emphasized that the MSA with IBM/Kyndryl would benefit the ATCO Distribution Utilities and their customers by leveraging and deriving benefit from more streamlined support services for applications and end users, new cloud application opportunities, and more agile and flexible delivery methods.[322]

329. At the same time, the ATCO Distribution Utilities emphasized that a detailed rate comparison between the Wipro MSA and the IBM/Kyndryl MSA was not possible because of the significant differences in the types and volumes of services supplied under the two MSAs.[323]

330. The ATCO Distribution Utilities confirmed that the IBM/Kyndryl MSA was not subject to a competitive procurement process, or a standard RFP process. In responses to IRs from the Commission and the UCA,[324] ATCO Electric explained that it did not go to a competitive procurement because it was necessary to negotiate with IBM on a confidential basis.

331. In response to IRs from the CCA,[325] the ATCO Distribution Utilities stated that they were paying termination and transition fees for the move from Wipro to IBM/Kyndryl, totalling close to [redacted] While the ATCO Distribution Utilities made it clear that these costs would not be passed on to ratepayers,[326] the [redacted] termination and transition raised additional questions as to why ATCO and the ATCO Distribution Utilities had changed IT service providers.

332. In response to IRs from the Commission, the ATCO Distribution Utilities also expressed [redacted][327]

333. In its IR responses, ATCO Gas also emphasized that "… the PBR incentives and IT Common Matters Decision 20514-D02-2019 were factors in the final decision, as ATCO Gas had the incentive to minimize its actual IT costs during the PBR term."[328]

334. In rebuttal evidence, the ATCO Distribution Utilities continued to assert that they had the incentive to minimize IT costs during the PBR term and that they reduced their costs by [redacted] and (ii) negotiating a new arm's-

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[322] Proceeding 26615, Exhibit 26615-X0041-C, ATCO Gas Summary to AUC Request on IT Costs, PDF page 7, and Exhibit 26615-X0110-C, AED Summary to AUC Request on IT Costs, PDF page 7.
[323] Proceeding 26615, Exhibit 26615-X0110-C, AED Summary to AUC Requests on IT Costs, PDF pages 3-4. Exhibit 26616-X0041-C, ATCO Gas Summary to AUC Request on IT Costs, PDF pages 3-4.
[324] Exhibit 26616-X0135-C, AG-AUC-2022-FEB17-007(h), PDF page 46; Proceeding 26615, Exhibit 26615-X0236, AE-UCA-2022JAN21-001(l).
[325] Proceeding 26615, Exhibit 26615-X0188-C, AE-CCA-2022JAN14-013(a) and (c); Exhibit 26616-X0132.02-C, AG-CCA-2022FEB17-006(d).
[326] Proceeding 26615, Exhibit 26615-X0110-C, AED Summary to AUC Request on IT Costs, PDF page 7.
[327] Proceeding 26615, Exhibit 26615-X0239-C, AE-AUC-2022JAN21-001(b)-(c)-CONF, Exhibit 26616-X0134-C, AG-AUC-2022FEB17-001(b)-CONF.
[328] Exhibit 26616-X0134-C, AG-AUC-2022FEB17-001(c)-CONF.

length MSA with IBM for services starting in 2021. The ATCO Distribution Utilities confirmed that these cost savings were reflected in the 2023 forecast.[329]

335. In the ATCO Gas rebuttal evidence, which was the last evidence filed by either of the ATCO Distribution Utilities prior to the oral hearing, ATCO Gas placed an additional emphasis on [redacted] with details that had not previously been placed on the record of this proceeding or Proceeding 26615:

> [redacted]
>
> [redacted]
>
> [redacted]
>
> [redacted]
>
> [redacted][330]

336. At the oral hearing, both ATCO Gas and ATCO Electric continued to emphasize that [redacted] and the move to IBM/Kyndryl. [redacted][331] [redacted][332]

329 Exhibit 26616-X0233, ATCO Gas rebuttal evidence, PDF page 56, paragraph 15; Proceeding 26615, Exhibit 26615-X0424, ATCO Electric rebuttal evidence, PDF page 8, paragraph 14.
330 Exhibit 26616-X0233-C, ATCO Gas rebuttal evidence, paragraphs 132-136.
331 Transcript, Volume 1 - Confidential, page 110, lines 1-16.
332 Transcript, Volume 1 - Confidential, page 117, lines 15-20.

337. The position of the ATCO Distribution Utilities on the [redacted] also changed during the course of the proceeding. While the ATCO Distribution Utilities had stated in their applications and IR responses that the decision was driven by a need to mitigate the IT Common Matters decision and lower costs,[333] [redacted][334] [redacted][335]

338. Notwithstanding multiple questions directed at the ATCO Distribution Utilities regarding the costs associated with the termination of the Wipro MSAs and transition to the IBM/Kyndryl MSA, [redacted][336] [redacted]

339. [redacted][337] [redacted][338]

340. The Commission notes its concern with the ATCO Distribution Utilities' evolving explanation for the [redacted], and the move to IBM/Kyndryl, as well as the failure to provide important details in relation to the costs of transitioning to the IBM/Kyndryl MSA until nearly the end of the confidential evidentiary portion of the hearing. This issue is further addressed in Section 8.7, which sets out the Commission's findings on the credibility of the evidence provided by the ATCO Distribution Utilities' on this subject.

[333] Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, PDF page 35, paragraph 107, and Exhibit 26615-X0234-C, AE-AUC-2022JAN21-001(b); Exhibit 26616-X0018, ATCO Gas application, PDF pages 36-37, paragraph 110.

[334] Transcript, Volume 1 - Confidential, page 117, lines 21-23.

[335] Transcript, Volume 2 - Confidential, page 233, lines 7-12.

[336] Exhibit 26616-X0274-C, ATCO Gas Confidential Undertaking 12.

[337] Transcript, Volume 2 - Confidential, page 317, lines 16-25, and page 318, lines 1-17.

[338] Transcript, Volume 2 - Confidential, page 323, lines 20-25, page 324, lines 1-25, and page 325, lines 1-7.

## 8.4 Intervener evidence

341. Calgary submitted that the ATCO Distribution Utilities should be provided with the same funding approved in the IT Common Matters decision, together with a further reduction to reflect an efficiency factor in 2023.[339]

342. Calgary further submitted that because the IBM/Kyndryl MSA was not competitively tendered, there was no evidence that it reflected FMV. Calgary asserted that [redacted] Calgary also pointed to evidence put forward by the ATCO Distribution Utilities asserting that the Wipro MSA and IBM/Kyndryl MSA were not comparable. Calgary argued that the ATCO Distribution Utilities, having admitted that the two contracts were not comparable, were thus precluded from relying on the [redacted] to claim that the IBM/Kyndryl rates reflected FMV.

343. In response to the ATCO Distribution Utilities' claim that the IBM/Kyndryl MSA could not be competitively tendered [redacted] He noted that for any vendor to prepare an agreement, it would need to have details on all of the applications and volumes. He questioned how that information could have been provided [redacted][340]

344. Calgary also provided evidence regarding the technical capabilities and professional reputation of Wipro among North American IT service providers. In an Everest Group 2022 Assessment, Wipro was categorized as one of the leading companies in North America, near the top of the group based on vision and capability (measuring the ability to deliver services successfully).[341] [redacted][342]

345. Calgary provided comparative evidence regarding the ATCO Distribution Utilities' IT costs. J. Stephens noted that in 2023, the IT operational spend for ATCO Gas would be 5.5 per cent of revenues. He compared this to his understanding of a typical utility's IT spend being between two per cent (median) and four per cent (75th percentile).[343] He also compared the IT O&M 2023 forecast of ATCO Electric against that of Fortis, with ATCO Electric projecting 3.6 per cent of its revenue requirement on IT O&M or $20,102 per FTE, while Fortis projected only 1.3 per cent, or $7,236 per FTE.[344]

346. In final argument during the Confidential Module, Calgary argued that if the ATCO Distribution Utilities had to use the IT Common Matters calculations for 2023, and carry them

339 Exhibit 26616-X0199, City of Calgary Written Evidence, PDF page 7; Proceeding 26615, Exhibit 26615-X0303, PDF pages 5 and 14, Evidence ID 26615 City of Calgary.
340 Transcript, Volume 2 - Confidential, page 283, lines 2-3.
341 Proceeding 26615, Exhibit 26615-X0339.01-C, Stephens Consulting Supplemental Evidence, PDF page 14.
342 Transcript, Volume 1 - Confidential, page 130, lines 8-14 (W. Dalton); Transcript, Volume 2, page 227, lines 7-12 (W. Dalton).
343 Exhibit 26616-X0208-C, Stephens Consulting evidence, 26616 Confidential, PDF page 44.
344 Proceeding 26615, Exhibit 26615-X0339.01-C, Confidential - Supplemental Evidence of Stephens Consulting Ltd., PDF page 26.

through to the end of PBR, [redacted][345]

347. The UCA suggested that the key drivers to terminate the Wipro contract and enter into a new contract with IBM appeared to be a "blatant attempt to circumvent the AUC decision in proceeding 20514,"[346] and proposed that there be a downward adjustment to IT costs to align with the rates approved in the IT Common Matters decision.

## 8.5 Commission findings regarding IBM/Kyndryl MSA costs

348. The Commission has determined that it will apply a 15 per cent reduction to the IBM/Kyndryl IT managed services costs for each of ATCO Electric and ATCO Gas. Its reasons for applying those reductions are set out below, and are organized as follows.

349. First, the Commission outlines the key matter at issue, which is the determination of the reasonableness of costs for the IBM/Kyndryl IT managed services for the ATCO Distribution Utilities. For the reasons set out below, the Commission does not agree with the interveners that it should simply apply the findings and glide path set out in the IT Common Matters decision.

350. The Commission then examines the evidence regarding the costs of IT managed services provided under the IBM/Kyndryl contract. [redacted]

351. This is followed by an examination of the evidence regarding the decision of ATCO, and by extension the ATCO Distribution Utilities, to sole-source the IBM/Kyndryl contract. The Commission does not accept the ATCO Distribution Utilities' explanation for sole-sourcing the IBM/Kyndryl contract. The Commission further finds that sole-sourcing the IBM/Kyndryl contract does not result in forecast costs that are reasonable.

352. Finally, the Commission outlines its concerns with the ATCO Distribution Utilities' evidence regarding the move from the Wipro MSAs to the IBM/Kyndryl MSA. The evolving explanations for the move to the IBM/Kyndryl MSA over the course of the two proceedings that continued into the oral hearing was a significant concern, and raised questions regarding the credibility of the evidence provided by the ATCO Distribution Utilities on the Wipro and IBM/Kyndryl matters.

### 8.5.1 Reasonability of IBM/Kyndryl costs are in issue

353. The Commission must determine whether the ATCO Distribution Utilities' IT costs are just and reasonable for inclusion in their respective 2023 forecast revenue requirements. The Commission does not question the ATCO Distribution Utilities' right to terminate the Wipro

[345] Transcript, Volume 3 - Confidential, page 379, lines 16-25, page 380, lines 1-25, page 381, lines 1-19 (D. Evanchuk).
[346] Exhibit 26616-X0203, UCA evidence, PDF page 21.

MSA or move to a new IT services provider.[347] As the Commission stated in Decision 25663-D01-2021:[348]

> 173. … In the IT Common Matters decision, the Commission considered whether to approve the prices contained in the IT master service agreements between the ATCO Utilities and Wipro for inclusion in each of the regulated utilities' revenue requirements. **No determinations were made on new services and no restrictions were imposed against IT services provided other than by Wipro; nor were there any directions to apply the IT Common Matters reductions to all IT services irrespective of the service provider.** [emphasis added]

354. The Commission agrees with the ATCO Distribution Utilities that Decision 20514-D02-2019 never stipulated that the ATCO Utilities could only use Wipro, nor did it require that the IT Common matters reductions be applied to all IT services. Further, the ATCO Distribution Utilities maintained that their rights to active governance of the relationship, including the right to terminate the Wipro relationship, were never suspended by Decision 20514-D02-2019. The Commission agrees with these propositions, subject of course to the Commission's obligation to ensure that any new contract results in just and reasonable rates.

355. The ATCO Distribution Utilities bear the onus of demonstrating that the inclusion of the IBM/Kyndryl IT MSA costs in 2023 forecast revenue requirement results in just and reasonable rates. As noted in the IT Common Matters decision, "there is no singular approach to the determination of just and reasonable rates. Rather, as was acknowledged by all parties in their submissions, in the context of examining the inclusion of costs for IT services in revenue requirement, the Commission has historically considered and employed a number of different tests, including reasonability and prudence; no harm; least cost alternative; and FMV."[349] As such, the Commission is afforded significant discretion when testing costs and, if required, applying a reduction to any forecast costs.

356. The ATCO Distribution Utilities submitted that the prices negotiated with IBM/Kyndryl are representative of FMV. They provided three different price comparisons to support their forecast IT costs:

[redacted]

(ii) the negotiated IBM/Kyndryl rates set in 2020; and

(iii) the prescribed IT Common Matters rates, which were based on the Proceeding 20514 record over the 2017-2018 time period.

357. The ATCO Distribution Utilities argued that the IT rates approved in the IT Common Matters decision were unattainable in the market and therefore are not just and reasonable. As evidence of this contention, they cited the rates subsequently negotiated with IBM/Kyndryl.[350] They maintained that the [redacted] and the negotiated

[347] Exhibit 26616-X0052-C, Article 29, Wipro MSA.
[348] Decision 25663-D01-2021: ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., 2021-2023 General Rate Application, Proceeding 25663, March 1, 2021.
[349] Decision 20514-D02-2019, paragraph 61.
[350] Proceeding 26615, Exhibit 26615-X0234-C, AE-AUC-2022-001(b), Exhibit 26616-X0135-C, AG-AUC-2022FEB17-005(b).

arm's-length rates with IBM/Kyndryl represented just and reasonable rates for IT services attainable in the market.[351]

358. The Commission finds that [redacted] and the negotiated IBM/Kyndryl rates are not representative of FMV, for the reasons that follow.

### 8.5.2 [redacted]

359. In the course of the oral hearing, the ATCO Distribution Utilities confirmed that [redacted][352] [redacted][353] [redacted][354]

360. [redacted] to the preferred first quartile approach cited in the IT Common Matters decision.[355] [redacted]

361. The Commission further finds that given the differences between the Wipro MSA and the IBM/Kyndryl MSA, the rates in the contracts were not comparable. The ATCO Distribution Utilities were asked to compare the Wipro MSA and IBM/Kyndryl MSA in the course of proceedings 26615 and 26616, and advised that they were unable to compare the two contracts.[356] The ATCO Distribution Utilities explained the differences as follows:[357]

> … a line by line or service-id to service-id comparison is not possible when comparing IBM/Kyndryl to Wipro or IT Common Matters costs. As seen in ATCO Gas' response to (a), while the goal of the business outcome may be similar (e.g. keeping critical systems, applications and end user computing working) the way these and new services are structured, performed and delivered are different, therefore a detailed rate comparison is not possible.

362. [redacted] the Commission is not persuaded that the [redacted] can be relied on to establish that the IT rates under the IBM/Kyndryl MSA are just and reasonable.

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351 Proceeding 26615, Exhibit 26615-X0234-C, AE-AUC-2022JAN21-002(b).
352 Transcript, Volume 1 - Confidential, page 121, lines 17-21 (W. Dalton questioned by L. Berg).
353 A tower is a grouping of related or similar services (e.g., services related to storage could fall under a storage tower).
354 Exhibit 26616-X0134-C, PDF page 17; Transcript, Volume 1 - Confidential, page 120, lines 8-14 (W. Dalton questioned by L. Berg).
355 Decision 20514-D02-2019, paragraph 217.
356 Proceeding 26615, Exhibit 26615-X0110-C, AED Summary to AUC Request on IT Costs, PDF pages 3-5; Exhibit 26616-X0041-C, ATCO Gas Summary to AUC Request on IT Costs, PDF pages 3-5.
357 Exhibit 26616-X0041-C, ATCO Gas Summary to AUC Request on IT Costs, page 4; Proceeding 26615, Exhibit 26615-X0110-C, AED Summary to AUC Request on IT Cost, PDF page 4.

363. The Commission finds that [redacted] offers no basis to conclude that the negotiated IT rates with IBM/Kyndryl are reasonable. The Commission cannot conclude that these rates represent FMV or would otherwise result in just and reasonable utility rates.

364. While the ATCO Distribution Utilities focused on [redacted] in the IT Common Matters Decision, the Commission observed that Wipro's MSA costs were higher because of the requirement that it purchase ATCO I-Tek for $204 million. ATCO gained from the Wipro purchase of ATCO I-Tek, and then took steps in an attempt to both [redacted] and to support its position that the negotiated IT rates with IBM/Kyndryl were reasonable.

### 8.5.3 Sole-source strategy

365. The ATCO Distribution Utilities confirmed that the MSA with IBM/Kyndryl was a sole-sourced contract.[358] This was notwithstanding that the value of the IBM/Kyndryl MSA meant it would normally be subject to an RFP process, and that sole-sourcing such a large contract was contrary to the ATCO Distribution Utilities' procurement policies.[359]

366. The ATCO Distribution Utilities asserted that the IBM/Kyndryl MSA was negotiated at arm's-length, and that the IBM/Kyndryl rates represented FMV. The ATCO Distribution Utilities submitted that in addition to the arm's-length negotiation, the fact that the forecast IBM/Kyndryl rates were [redacted] was further evidence that the IBM/Kyndryl rates were FMV.[360]

367. The Commission and the UCA asked the ATCO Distribution Utilities about market-based comparators and whether procurement practices were maintained, and an RFP process was used. The ATCO Distribution Utilities explained that:[361]

> It was determined that an RFP process to find an alternative service provider was too risky as it could result in, among other things: [redacted] Due to these factors, ATCO Gas negotiated with IBM on a confidential basis. Managing these risks was necessary to maintain safe and reliable operations of IT services. ATCO Gas' intention is to RFP managed services at the end of the IBM/Kyndryl contract in 2025.

368. The Commission finds the above-noted risks to be largely based on [redacted] The termination provisions in the Wipro MSAs are standard provisions common to IT agreements. [redacted] The evidence in the current proceeding is that [redacted] approximately $19.3 million by ATCO Electric and $32.4 million by ATCO

[358] Transcript, Volume 1 - Confidential, page 99, lines 17-25, page 100, lines 1-4 (W. Dalton questioned by L. Berg).
[359] Transcript, Volume 1 - Confidential, page 101, lines 6-24 (W. Dalton questioned by L. Berg).
[360] Exhibit 26616-X0135-C, AG-AUC-2022FEB17-006(b); Proceeding 26615, Exhibit 26615-X0234-C, AE-AUC-2022JAN21-002(b).
[361] Exhibit 26616-X0135-C, AG-AUC-2022-FEB17-007(h), PDF page 46; Proceeding 26615, Exhibit 26615-X0236-C, AE-UCA-2022JAN21-001(l).

Gas [redacted][362] [redacted]

369. [redacted][363] [redacted][364] [redacted]

370. The Commission also does not accept that the sole-source process led to a contract that reflects FMV. The ATCO Distribution Utilities explained that they typically would have conducted a competitive procurement process for a contract of the size of the IT MSA. In response to Commission counsel's question on whether it is normal for the ATCO companies to not conduct an RFP process for a contract of such size, W. Dalton responded, "No, typically it isn't. Typically, we would do an RFP process in order to – to ensure that we were making sure we achieving the best possible pricing."[365]

371. Given that the ATCO and the ATCO Distribution Utilities did not conduct a competitive procurement process, the Commission is concerned that the ATCO Distribution Utilities' IT rates do not reflect FMV. Although the IT MSA reached between the ATCO Distribution Utilities and IBM/Kyndryl was negotiated between two arm's-length parties, the sole-sourced approach greatly weakens the likelihood that the IT rates were the rates that could be achieved in the competitive market for IT services.

372. In addition to the failure of ATCO to conduct a competitive RFP process to choose its successor IT provider, the evidence on the record of this proceeding is that IBM was already providing IT services to ATCO and was aware that ATCO was terminating its IT MSA with

362 Transcript, Volume 1 - Confidential, page 112, lines 22-25, page 113, lines 1-17.
363 Exhibit 26616-X0233-C, ATCO Gas rebuttal evidence, paragraph 134. Transcript, Volume 1 - Confidential, page 105, lines 12-25, page 106, lines 1-6.
364 Transcript, Volume 2 - Confidential, page 282, lines 18-25, page 283, lines 1-3.
365 Transcript, Volume 1 - Confidential, page 101, lines 6-11.

Wipro. The implications of this arrangement on the relative negotiating positions of ATCO and IBM were the subject of a discussion with J. Sharpe at the oral hearing:[366]

> The Chair questions the panel:
> Q. … The first is in relation to this question of the sole-sourcing with IBM and the fact that -- I'm paraphrasing, but I think what you said, Mr. Sharpe, is that IBM sort of knew what the -- knew the landscape, for lack of a better word, at ATCO, and that was an advantage, because it would be difficult to run an RFP without having potential bidders understand the nature of the work that needed to be done.
>
> But isn't it true, then, that IBM also knew this?
>
> That they were at a -- they were situationally advantaged? So you're in a negotiation with a company that realizes that ATCO is over a barrel, for lack of a better word, and needs to replace its current service provider with a new service provider quickly.
>
> A. MR. SHARPE: Yeah, so I think -- I think any negotiation there's points of strength and weakness, and there's points of strength and weakness as you go through the negotiation.
>
> [redacted] They also knew we -- well, they also knew we -- we were -- we had a lot of complexity going into it.
>
> So I would say you're correct. They -- they had some advantages there. I would say the advantages we have in -- in that negotiation is we knew our -- we knew the existing pricing. [redacted] And the back and forth with IBM, you know, would be -- well, it wasn't an overnight negotiation; it was quite extensive, actually. So the fact that we were able to keep pushing them back and keep pushing them down also shows that we had some good position around that negotiation.
>
> And obviously you're correct, [redacted] We wouldn't -- we wouldn't play out all of those cards obviously in a negotiation. You want to -- want to stay strong as you're, you know, moving through that. And I would say that's part of what our team did, because they were continually coming back to the steerco, and being sent back on do better.

373. The Commission considers that the above exchange highlights sole-sourcing concerns and the constraints on the ability of ATCO and the ATCO Distribution Utilities to negotiate IT rates that reflect FMV.

374. The Commission's concerns that sole-sourcing does not result in FMV are not mitigated by ATCO and the ATCO Distribution Utilities' use of the [redacted] in negotiations with IBM. Further, the ATCO Distribution Utilities' reliance on the [redacted] as an indicator of, or proxy for, FMV is problematic at best.

375. The Commission considers it is incumbent on the utility to negotiate an IT MSA to meet its requirements to effectively serve customers at the lowest possible cost, and as FMV represents a range of pricing, the ATCO Distribution Utilities should endeavour to seek first quartile (least cost) pricing whenever possible. The reliance on the [redacted]

[366] Transcript, Volume 2 - Confidential, pages 253 and 254, lines 1-16, respectively.

[redacted] is inconsistent with the expected objective that the ATCO Distribution Utilities should look to mitigate any cost impact on customers.

376. In addition, the Commission also finds that the ATCO Distribution Utilities selectively and inconsistently rely on the Wipro MSA to [redacted] while simultaneously arguing elsewhere in this proceeding that the two MSAs and the services provided thereunder are significantly different and that detailed cost comparisons are therefore not possible.

377. [redacted] The Commission considers it significant that after negotiating the sole-source contract with IBM/Kyndryl, the ATCO Distribution Utilities took no steps to validate the prices negotiated, notwithstanding the paucity of evidence to support the reasonableness of such pricing.

378. In the IT Common Matters decision, the Commission applied a reduction to IT MSA pricing due to the sourcing strategy and tender/bid process employed by the ATCO Utilities:[367]

> 345. In Section 5.1, the Commission found that the ATCO Utilities (or ATCO on behalf of the ATCO Utilities), failed to act prudently in their consideration of the IT sourcing alternatives available to them at the time, and that the requirement for the MSA service provider to purchase ATCO I-Tek served as a restriction on competition; limited the pool of potential bidders (because it excluded from the process all those interested in bidding only on the MSAs); and, ultimately, resulted in the MSA prices being higher than they would have otherwise been. Stated another way, **achieving a greater number of bidders would have been accomplished if there had been no requirement for the MSA service provider to purchase ATCO I-Tek, and more bidders would have likely resulted in lower MSA pricing.**[368] [emphasis added]

379. The Commission notes that in the IT Common Matters decision, the Commission made clear that "… it is incumbent upon the utility to give reasonable consideration to the alternatives available to it and to document the basis for its decision-making so that the Commission has a view into the mechanics of the process and any potential effect on rates"[369] and that "… the ATCO Utilities must also demonstrate that the MSA pricing is reasonable, that its reasonableness can clearly be determined, and that the price paid is associated with the least cost option that meets the needs of the ATCO Utilities."[370] It went on in that decision to find that there were deficiencies in the evidence of the ATCO Utilities and that it therefore had "no reasonable basis upon which to conclude that an adequate consideration of the alternatives occurred, good judgment was exercised, or that a prudent sourcing decision was made."[371]

380. In the IT Common Matters decision the Commission expressed concern with the fact that the tendering process chosen led to fewer bidders. In this case, ATCO and the ATCO

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[367] In the IT Common Matters decision, ATCO Electric Transmission and ATCO Electric Distribution, divisions of ATCO Electric Ltd.; ATCO Gas and ATCO Pipelines, divisions of ATCO Gas and Pipelines Ltd. were referred to collectively as "the ATCO Utilities." In the current proceeding, the reference to "the ATCO Distribution Utilities" pertains only to the distribution utilities, ATCO Gas and ATCO Electric.

[368] Decision 20514-D02-2019, paragraph 345.

[369] Decision 20514-D02-2019, paragraph 98.

[370] Decision 20514-D01-2019, paragraph 99.

[371] Decision 20514-D02-2019, paragraph 109.

Distribution Utilities took matters a step further, and embarked on a sole-source process where there were **no other bidders.** In the current proceeding the ATCO Distribution Utilities seek to recover the costs associated with IT services that ATCO and the ATCO Distribution Utilities chose to sole-source despite the clear concerns raised by the Commission in the IT Common Matters decision and the associated reductions imposed based on that previous sourcing and bid processes.

381. The Commission was clear in the IT Common Matters decision in its expectations with respect to the procurement of services of this nature and in the requirements to be met for a determination of reasonableness in respect of the costs associated therewith. The Commission finds itself similarly situated based on the record of the current proceeding, with no reasonable basis upon which to conclude that ATCO and the ATCO Distribution Utilities adequately considered the alternative options available for the procurement of IT services, that good judgment was exercised, or that a prudent sourcing decision was made.

382. The ATCO Distribution Utilities have failed to demonstrate the prudence of the sole-sourcing decision and that the best interests of customers were taken into account in making that decision or, that in the end, customers would be required to pay no more than is just and reasonable. The Commission is unable to conclude that the sole-sourcing strategy was reasonable and resulted in MSA pricing comparable to what would have prevailed under a competitive bid process.

383. Having regard to the failure of ATCO or the ATCO Distribution Utilities to conduct a competitive procurement process for the IBM/Kyndryl MSA, which would be a standard ATCO Distribution Utilities approach for a contract of this size, the Commission finds that the rates and underlying costs to which the ATCO Distribution Utilities have committed under the IBM/Kyndryl contract are not just and reasonable.

### 8.6 Adjustment to forecast IT costs

384. The Commission is not persuaded that the evidence supports a finding that the IBM/Kyndryl IT rates are just and reasonable. Further, the Commission notes that J. Stephens' evidence indicated that the total IT operational spend as a percentage of revenue for each of ATCO Electric and ATCO Gas is greater than nine per cent and five per cent, respectively, which he claimed is much higher than industry norms or those of ATCO Pipelines and ATCO Electric Transmission.[372] While not determinative, this overall IT operational spend metric also supports the Commission's conclusion that the 2023 forecast IT costs for the ATCO Distribution Utilities are not reasonable, and exceed those of comparators, including their affiliated transmission utilities.

385. As noted earlier, absent evidence that provides a reasonable comparable cost or benchmark, the Commission must use its judgment, as an expert regulatory tribunal, to set IT rates that are just and reasonable. The Commission notes that both the UCA and Calgary recommended that the IT costs that were determined in Proceeding 20514 for 2023 be the only IT costs that are allowed in rates. Calgary's witness, J. Stephens, recommended that 2023 IT MSA O&M costs be reduced to $27,817,000 for ATCO Gas and $15,282,000 for ATCO

[372] Proceeding 26615, Exhibit 26615-X0339.01, Evidence of Stephens Consulting, pages 5-6; Exhibit 26616-X0208-C, Evidence of Stephens Consulting, page 44.

Electric. In coming to these reductions, he relied on the forecast Wipro charges after applying the reductions ordered in Decision 20514-D02-2019.

386. J. Stephens also recommended reductions to the ATCO Distribution Utilities' forecast IT indirect and direct capital costs, and for an efficiency factor to be applied to both IT capital and O&M costs. A discussion of these issues is provided in sections 8.8 and 8.9 of this decision.

387. For the reasons set out above, the Commission finds that a downward adjustment to the ATCO Distribution Utilities' IT rates and related costs is required. The IT rates approved in Decision 20514-D02-2019 offer one option for the Commission to consider in terms of adjusting IT rates and costs, as these are the only IT rates that have been approved by the Commission to be just and reasonable. That being said, the Commission is not prepared to reduce the ATCO Distribution Utilities' IT costs to align with costs based on the IT rates approved in the IT Common Matters decision. These rates are derived from the services and associated costs set out in the Wipro MSA, which are of minimal relevance to the services the ATCO Distribution Utilities are expected to receive from IBM/Kyndryl in 2023. Therefore, in the specific circumstances of this proceeding, the Commission does not find that using Commission-approved rates based on a previous contract is reasonable.

388. In this context, it is the Commission's view, that any IT adjustment should be based on the evidence filed in this proceeding and be applied to the 2023 IT managed services forecast costs under the IBM/Kyndryl MSA pursuant to which the distribution utilities are providing service to customers. The Commission considers that the ATCO Distribution Utilities' reasoning for sole-sourcing IT services [redacted] and the ATCO Distribution Utilities' customers should not bear the burden of higher IT rates based on a sourcing strategy that did not benefit from a competitive procurement process. In the IT Common Matters decision, the Commission adjusted IT rates based on the chosen sourcing strategy employed by ATCO:

> 352. Having regard to the available evidence, including the informational value of the [redacted] bids as described, and exercising its judgment, the Commission concludes that on average, the MSA pricing is 10 per cent too high as a consequence of the sourcing strategy chosen and the tender/bid process employed. A 10 per cent adjustment aligns with PAC's [PA Consulting] recommended reduction of 10 to 20 per cent for a well-managed competitive outsourcing process [redacted] As will be discussed below, a 10 per cent adjustment also roughly aligns with the Commission's finding that the Gartner benchmark report establishes that the first-year MSA pricing is [redacted][373]

389. In addition, the ATCO Distribution Utilities provided no persuasive evidence that the IT rates with IBM/Kyndryl are just and reasonable. Based on the factors identified above, the Commission directs each of the ATCO Distribution utilities to reduce their 2023 IT managed services forecast costs by 15 per cent. In coming to this disallowance, the Commission reiterates that, unlike the Commission's concerns in the IT Common Matters decision about the shortcomings in the competitive procurement process employed by ATCO prior to selecting Wipro as its external managed IT services provider, here there was no competitive procurement process **of any kind** leading to the selection of IBM/Kyndryl. A 15 per cent reduction is

[373] Decision 20514-D02-2019, paragraph 352.

appropriate in the circumstances of this case, given the paucity of relevant or compelling evidence to support the reasonableness of the IBM/Kyndryl rates.

390. The Commission agrees with J. Stephens' recommendation that the ATCO Distribution Utilities be required to provide similar detail to Table 4 of his evidence in a future rate or tariff application. The Commission considers that additional clarity around IT costs is necessary. The Commission therefore directs the ATCO Distribution Utilities to provide information on total IT expenditures, the MFR accounts in which these costs are recorded, an identification of all IT corporate costs and the method used to allocate IT costs to ATCO distribution and transmission utilities in future rate proceedings.

## 8.7 Credibility of ATCO's evidence

391. The Wipro MSAs with ATCO had a total contract value in excess of [redacted] over a 10-year period.[374] The total contract value of the IBM/Kyndryl MSA is [redacted][375] Termination and transition costs for moving from the Wipro MSAs to the IBM/Kyndryl MSA [redacted]

392. The Commission would have expected such a significant contractual change to have been supported by very well-defined and comprehensive business reasons that were clearly articulated at the outset of the applications. Instead, the record was unclear and evolved over time. The ATCO Distribution Utilities initially stated that the IBM/Kyndryl agreement was put into place to address "changing needs, including the need to mitigate the adverse effects of [the IT Common Matters decision]."[376] Costs were also emphasized, with the ATCO Distribution Utilities asserting that they were highly motivated to secure services for the lowest cost, and that the IBM/Kyndryl contract fully reflected those incentives and efficiencies.[377]

393. However, late in the present proceeding, after evidence regarding close to [redacted] in termination and transition costs related to termination of the Wipro contract was filed following IRs from Calgary,[378] the ATCO Distribution Utilities began to increasingly redirect the focus of their evidence [redacted][379]

394. During the oral hearing, the ATCO Distribution Utilities' witnesses focused on [redacted][380] [redacted]

374 Decision 20514-D02-2019, paragraph 196.
375 Transcript, Volume 2 - Confidential, page 206, lines 9-15.
376 Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, paragraph 107, and Exhibit 26616-0018, ATCO Gas application, paragraph 106.
377 Exhibit 26616-X0018, ATCO Gas application, paragraph 110, and Proceeding 26615, Exhibit 26615-X0023, ATCO Electric application, paragraph 110.
378 [redacted]
379 Exhibit 26616-X0233-C, ATCO Gas rebuttal evidence, PDF page 51, paragraph 134.
380 Transcript, Volume 2 - Confidential, page 233, line 7.

[redacted][381] [redacted][382] [redacted][383]

395. The Commission is concerned about the evolving explanations offered by the ATCO Distribution Utilities for the termination of the Wipro contract and the move to IBM/Kyndryl. The rationale for this decision should have been clear from the outset of the applications. The rationale should not have been provided on a piece-meal basis, evolving as each piece was disclosed. [redacted]

396. In view of the above, the Commission finds itself less than fully confident in the credibility of the ATCO Distribution Utilities' witnesses that provided both written and oral evidence regarding the Wipro MSA and the IBM/Kyndryl contract.

## 8.8 IT capital costs

397. ATCO Gas forecast 2023 IT MSA indirect capital of $5.240 million and IT MSA direct capital of $3.872 million employing a mechanistic approach based on its escalated 2018-2020 average.[384] ATCO Gas explained that all capital numbers were forecast using a mechanistic approach based on the escalated 2018-2020 average, with the exception of the CIS forecast.[385]

398. Similarly, ATCO Electric forecast 2023 IT MSA indirect capital of $5,663,000 and IT MSA direct capital of $3,170,000 using a mechanistic approach based on its escalated 2018-2020 average.[386]

399. Calgary's witness, J. Stephens, recommended a 10 per cent reduction be applied to ATCO Gas's 2023 IT MSA recurring capital and a 20 per cent reduction be applied to ATCO Electric's IT MSA recuring capital. Calgary argued that reductions to recuring capital were warranted because the ATCO Distribution Utilities failed to provide sufficient evidence on the record that the 2018-2023 IT MSA recurring capital costs reflected cost reductions from the IT Common Matters decision.

381 Transcript, Volume 1 – Confidential, page 117, lines 21-23.
382 Exhibit 26616-X0274-C, ATCO Gas Confidential Undertaking 12.
383 Transcript, Volume 2 - Confidential, page 323, lines 20-25; page 324, lines 1-25; page 325, lines 1-7 (J. Sharpe questioned by D. Romaniuk).
384 Exhibit 26616-X0150, AG-CAL-2022FERB17-008(c)-(d) Attachment 1.
385 Exhibit 26616-X0139-C, AG-CAL-2022FEB17-008(c)-(d).
386 Proceeding 26615, Exhibit 26615-X0339.01, Supplemental evidence of Stephens Consulting, page 19.

400. In rebuttal evidence, the ATCO Distribution Utilities submitted that the escalated 2018-2020 average reflects the actual IT direct and indirect spend for the years 2018 to 2020, adjusted for inflation and customer growth. This mechanistic approach is consistent with how other capital forecasts were derived. The ATCO Distribution Utilities maintained that the mechanistic approach is a reasonable indicator of future IT spend and complies with the streamlined, hybrid approach directed by the Commission. The ATCO Distribution Utilities submitted that they used the 2018-2020 historical spend at the prescribed IT Common Matters rates, which includes the glide path for those years.[387]

401. In Section 5.2 of Decision 26615-D01-2022 and in Section 5.2 of this decision, the Commission made determinations on the escalators used by ATCO Electric and ATCO Gas, respectively, for the purposes of calculating their escalated 2018-2020 averages used under the mechanistic approach. The Commission does not consider that an additional reduction to IT capital spend from 2018-2020 is required because the prescribed IT Common Matters rates are embedded in the ATCO Distribution Utilities' calculations of their respective escalated 2018-2020 averages that were used to forecast the actual IT direct and indirect costs for 2023, consistent with other capital forecasts that used the mechanistic approach.[388]

## 8.9 Efficiency factors

402. In evidence, Calgary suggested that further efficiency factors be applied to IT costs to provide customers with incremental efficiencies and savings in IT costs approved in Decision 20514-D02-2019. Calgary proposed efficiency factors of 15.5 per cent for O&M and 33 per cent for capital for ATCO Electric, resulting in a total 2023 revenue requirement reduction of $0.585 million.[389] For ATCO Gas, Calgary proposed efficiency factors of 12.2 per cent for O&M and 83.4 per cent for capital,[390] resulting in a total 2023 revenue requirement reduction of $0.772 million ($0.729 million for O&M and $0.043 million for capital).[391] Calgary explained that its proposed efficiency factors would ensure that customers share the efficiencies achieved during PBR.[392]

403. As shown in Attachment 1 to Calgary's evidence, Calgary's recommended efficiency factors were based, in part, on the lowest year O&M and capital costs.[393] In Section 5.1 of this decision, the Commission determined it will not use the lowest cost year approach for the purposes of this rebasing.

404. The Commission is not persuaded that an incremental efficiency factor should be applied to the ATCO Distribution Utilities' IT costs as the adjustment to IT costs directed in Section 8.6 reflects the Commission's determination of just and reasonable IT rates. Therefore, no further reductions are required. Further, the Commission is of the view that PBR benefits should be

[387] Exhibit 26616-X0233, ATCO Gas rebuttal evidence, pages 67-68, paragraph 186. Proceeding 26615, Exhibit 26615-X0424, ATCO Electric rebuttal evidence Part 2 of 2 (Confidential), PDF page 18, paragraph 44.
[388] Proceeding 26615, Exhibit 26615-X0424-C, PDF page 18, Section 2.1.3; Exhibit 26616-X0233-C, PDF page 67, Section 5.1.3.
[389] Proceeding 26615, Exhibit 26615-X0303, City of Calgary evidence, pages 14-15.
[390] Exhibit 26616-X0200, Attachment 1 AG efficiency factor for IT costs.
[391] Exhibit 26616-X0199, City of Calgary written evidence page 8.
[392] Transcript, Volume 2 - Confidential, page 287, lines 1-11.
[393] Exhibit 26616-X0200, Attachment 1 AG efficiency factor for IT costs.

shared with customers for all costs included in the COS review applications and not on a narrow subcomponent of costs. Calgary's proposed efficiency factors are therefore denied.

## 9 Compliance filings to this decision

405. Throughout this decision, the Commission has issued various directions to ATCO Gas, ATCO Electric and Apex. The Commission directs each of ATCO Gas and Apex to file a compliance application to finalize their respective 2023 forecast revenue requirements to reflect the approvals, denials, and adjustments in this decision by October 3, 2022. ATCO Electric must reflect the adjustments from this decision in its September 26, 2022, compliance filing, directed by the Commission in Decision 26615-D01-2022.

406. In addition to responding to the Commission's directions, the utilities must include in their respective compliance filings the calculation of 2023 rates based on the approved revenue requirement. Each utility shall include in its compliance filings all information that typically accompanies the calculation of rates, including the following:

- 2023 billing determinant forecast reflective of the last approved Phase 2 methodologies and most recent data.
- 2023 distribution tariff based on the approved revenue requirement and the associated bill impact analysis.
- Terms and conditions of service for 2023 for approval.
- True-up of the prior approved deferral accounts such as the amounts included in the Y factor.
- Currently approved deferral accounts and rate riders, which shall continue to be applied in 2023 unless stated otherwise in this decision. The differences between forecast and actual costs for amounts in these accounts will subsequently be trued up in the annual PBR rate adjustment filings.
- Any other items required to support the proposed 2023 distribution tariff.

407. To assist the Commission in reviewing the compliance of ATCO Gas and Apex with the directions in this decision, the Commission directs both utilities to support their revised 2023 revenue requirement, inclusive of 2023 forecasts, with accompanying Excel schedules. Specifically, each of the 2023 forecast amounts contained in the rebasing templates should either have a working formula showing how the number was determined (e.g., a formula that shows the calculation of the escalated 2018-2020 average), or reference to an associated working paper where such calculation was performed. The calculations should clearly illustrate how the utility's compliance with a Commission direction (e.g., denial of a capital project or the application of approved escalators) was achieved.

## 10 Order

408. It is hereby ordered that:

(1) Each of ATCO Gas and Apex Utilities Inc. shall file a compliance filing in accordance with the directions set out in this decision by October 3, 2022.

(2) ATCO Electric Ltd. (distribution) shall file a compliance filing in accordance with the directions set out in this decision by September 26, 2022.

Dated on September 1, 2022.

**Alberta Utilities Commission**

*(original signed by)*

Kristi Sebalj
Vice-Chair

*(original signed by)*

Cairns Price
Commission Member

*(original signed by)*

Bohdan (Don) Romaniuk
Acting Commission Member

# Appendix 1 – Proceeding participants

| Name of organization (abbreviation)<br>Company name of counsel or representative |
|---|
| Apex Utilities Inc. (Apex or AUI)<br>Stikeman Elliott LLP |
| ATCO Gas North (ATCO Gas)<br>Bennett Jones LLP |
| The City of Calgary (Calgary)<br>McLennan Ross Barristers & Solicitors |
| NOVA Gas Transmission Ltd. (NGTL) |
| Consumers' Coalition of Alberta (CCA) |
| Office of the Utilities Consumer Advocate (UCA)<br>Brownlee LLP<br>Russ Bell & Associates Inc. |
| Direct Energy Marketing Limited |

Alberta Utilities Commission

Commission panel
- K. Sebalj, Vice-Chair
- C. Price, Commission Member
- B. Romaniuk, Acting Commission Member

Commission staff
- P. Khan (Commission counsel)
- L. Berg (Commission counsel)
- S. Sharma
- A. Spurrell
- E. Deryabina
- M. McJannet
- C. Robertshaw
- B. Edwards

# Appendix 2 – Oral hearing – registered appearances

| Name of organization (abbreviation)<br>Name of counsel or representative | Witnesses |
|---|---|
| Consumers' Coalition of Alberta (CCA)<br>J. Wachowich | |
| Apex Utilities Inc. (Apex)<br>D. Langen | G. Feltham<br>M. Stock<br>D. Paquette<br>I. Khaled |
| ATCO Gas North (ATCO Gas)<br>L. Smith<br>S. Assie | J. Sharpe<br>C. Severson<br>J. Hodgson<br>N. Palladino<br>W. Dalton<br>S. Schubert<br>S. Ellis<br>G. Galluzzi |
| NOVA Gas Transmission Ltd. (NGTL)<br>E. von Engelbrechten | |
| Office of the Utilities Consumer Advocate (UCA)<br>T. Marriott<br>K. Rutherford | |
| The City of Calgary (Calgary)<br>D. Evanchuk | J. Stephens<br>B. Whyte<br>K. Wyllie |

## 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. The Commission directs the following adjustments to the applied-for escalation factors:
   (a) Both ATCO Gas and Apex are to use their actual labour cost increases for the period 2019-2020 in calculating their inflation escalators.
   (b) Both ATCO Gas and Apex are to reduce their proposed customer growth escalator by 15 per cent. ............................................................................ paragraph 6
2. The Commission directs each of ATCO Gas and Apex to recalculate their respective 2023 forecasts under the mechanistic approach to reflect the escalation factors approved in this decision. ........................................................................................ paragraph 7
3. Having determined that using the 2018-2020 average of historical costs is an effective way to ensure that efficiencies are passed on to customers, the Commission also reviewed ATCO Gas's and Apex's use of escalators. As explained in Section 3, under a mechanistic approach, the 2023 costs are forecast by escalating the average of actual 2018-2020 costs by the utilities' chosen escalation factors. The same escalated 2018-2020 average costs were also used by each of ATCO Gas and Apex to quantify their achieved efficiencies for costs forecast under a non-mechanistic approach and to justify the general reasonableness of those forecasts. Parties in this proceeding pointed out that, for this reason, the indexes used for escalating the 2018-2020 average play an important role in quantifying the achieved efficiencies and passing them on to customers. As further set out in Section 5.2 of this decision, the Commission agrees and directs certain changes to the proposed escalators. Overall, for costs forecast using a mechanistic approach, the Commission is satisfied that the use of the 2018-2020 average, escalated by indexes approved in Section 5.2, results in a 2023 forecast that is reasonably reflective of the efficiencies achieved during the PBR2 term.................................................. paragraph 97
4. To avoid similar challenges in identifying the achieved efficiencies and calculating the realized savings at the next rebasing, the Commission directs ATCO Gas and Apex to present proposals in Proceeding 27388 where the parameters for PBR3 plans will be set, on how efficiencies can be effectively quantified and tracked over time. ATCO Gas provided examples of some possible forward-looking productivity and/or efficiency measures, including: (i) O&M per customer; (ii) O&M per kilometre (km) of line; and (iii) O&M per GJ delivered. ATCO Gas emphasized the importance of service quality measures. Apex agreed that the three measures identified by ATCO Gas are possible candidates.......................................................................................... paragraph 103
5. Both ATCO Gas and Apex relied on the same weightings between CPI and labour costs currently established for the I factor. Both used data from well-known sources for their historical and forecast CPI. The Commission also accepts, for the purposes of this decision, the calculation of CPI and labour escalators on a calendar year basis (rather than a July to June basis as is currently done for the I factor calculation). Doing so aligns more closely with the utilities' costs and revenues, which are measured on a calendar year basis. Given the Commission's approval to use the most up-to-date data, the Commission

directs ATCO Gas and Apex to use the 2021-2023 CPI values as shown in tables 9 and 10 above in their respective compliance filings. The Commission denies ATCO Gas's request to further update its forecasts at the time of the compliance filing. .. paragraph 112

6. Regarding labour costs, both ATCO Gas and Apex used the Alberta AWE index as a substitute for their labour costs escalator for 2019 and 2020, and used their own actual or projected labour cost increases for 2021-2023. In the Commission's view, it is more methodologically sound to use the utility's own actual or forecast labour cost growth for the entire 2019-2023 period so that the data for both historical and forecast costs is consistent. The Commission considers the use of the utilities' actual and forecast labour costs is reasonable for purposes of the inflation escalator because the objective of this proceeding is to realign each of the utility's costs with revenues. Further, in Section 5.2.6 of this decision, the Commission reviews the 2021-2023 proposed labour cost escalators developed by the utilities, and finds them to be reasonable. As such, the Commission directs ATCO Gas and Apex to recalculate their 2019-2020 inflation indexes based on their own labour cost data using the same methodology used for developing their 2021-2023 labour cost indexes as shown, respectively, in tables 9 and 10 above. ........................ ........................................................................................................... paragraph 113

7. As a result, the Commission has determined that it is necessary to introduce an offset to the customer growth escalation factors used by both utilities to account for its findings that (i) there is not an observed one-to-one relationship between customer growth and utility costs; and (ii) there exist economies of scale that are not accounted for in the application of the customer growth escalator. Having reviewed the record and exercised its judgment, the Commission directs each of the utilities to reduce their proposed customer growth escalation factors by 15 per cent. ...................................... paragraph 129

8. ATCO Gas and Apex updated their respective 2021 capital costs with non-audited 2021 actual amounts on April 1, 2022. As set out in Section 7.1, the Commission examined the utilities' 2021 non-audited actual capital additions in this proceeding and, except as noted otherwise in this decision, finds these amounts to have been prudently incurred, subject to reviewing the explanations for variances between the non-audited 2021 actuals provided in April 2022 and audited actuals provided in Rule 005 filings. Therefore, the Commission directs ATCO Gas and Apex to incorporate the 2021 actual rate base, subject to the exceptions otherwise noted in this decision, into their compliance filings. ........................................................................................................... paragraph 146

9. For these reasons, the Commission finds that ATCO Gas's O&M and A&G forecasts derived using the mechanistic approach, and adjusted using the escalation factors approved in Section 5.2, are reasonable. The Commission directs ATCO Gas to recalculate its 2023 O&M costs forecast under the mechanistic approach to reflect the escalation factors approved in Section 5.2 of this decision. .......................... paragraph 158

10. The Commission agrees with the UCA that there is potential for cost duplication and it may be more efficient to take a more coordinated approach to the EREE program. The Commission sees no reason why ATCO Gas could not work collaboratively with the UCA and other utilities to deliver coordinated EREE programming, particularly because ATCO Gas has indicated the EREE programs are in the public interest. Accordingly, ATCO Gas's EREE program is denied. The Commission directs ATCO Gas to remove the expenditures associated with these programs and initiatives from its 2023 forecast in its compliance filing. ......................................................................... paragraph 173

11. For these reasons, the Commission finds that Apex's O&M forecasts derived using the mechanistic approach, and adjusted using the escalation factors approved in Section 5.2 of this decision, are reasonable. The Commission directs Apex to recalculate its 2023 O&M costs forecast under the mechanistic approach to reflect the escalation factors approved in Section 5.2 of this decision. ...................................................... paragraph 186

12. For the reasons set out in sections 6.3.2.1.1 to 6.3.2.1.3 below, the Commission is not persuaded by Apex's explanations for the large overall increases to TSU's 2022 and 2023 shared corporate services costs forecasts after several years of declining costs. The Commission also finds that the allocation percentage of shared corporate services costs to Apex from TSU should be changed. Finally, the Commission directs Apex to remove any TSU STIP costs in the TSU total cost pool prior to allocating any corporate costs to Apex. ........................................................................................................ paragraph 193

13. The Commission therefore directs Apex to reflect, in the compliance filing to this decision, the following adjustments to its 2023 shared corporate services costs forecast:

    (i) Remove any TSU STIP costs, if any, from the 2021 shared corporate services forecast costs to be used as the basis of allocation to Apex.

    (ii) Calculate the allowable 2023 forecast TSU cost pool to be allocated to Apex by escalating the 2021 forecast TSU cost pool to 2023 dollars using the inflation and customer growth escalators approved in Section 5.2 of this decision.

    (iii) Allocate to Apex the allowable 2023 forecast TSU cost pool calculated above by using the allocation percentage of 42.2 per cent. ....................... paragraph 194

14. The Commission finds total assets to be a more reasonable cost allocator for use in the MMF formula for the following reasons: (i) total assets is one of the three MMF composite allocators used consistently by the comparator utilities and was previously used by AltaGas; (ii) the Commission has previously found that the cost of gas should be included in the composite allocator; and (iii) corporate service support costs are driven by more than the net book value of property owned by each affiliate. The Commission therefore directs Apex to use total assets in place of the property factor as one of the three MMF composite factors for its 2023 forecast TSU corporate allocations, and to reflect this change in its compliance filing. ............................................................ paragraph 219

15. On balance, the Commission finds there to be insufficient evidence to support the proposition that Apex's ratepayers will be better off paying for TSU's employee STIP program benefits and incentives than these costs being borne by TSU's shareholders. The Commission, therefore, denies the inclusion of any TSU employee STIP costs in the corporate shared service allocation to Apex. If any TSU employee STIP costs were included in the 2021 TSU forecast cost pool (that will be used as the basis for Apex's 2023 forecast allocation as directed earlier in this decision), the Commission directs that they be removed to ensure that Apex's 2023 forecast shared corporate services costs exclude any TSU employee STIP costs. ....................................................... paragraph 227

16. The Commission finds that with the exception of NGSSC operating costs, the forecast costs in Apex's 2023 O&M deferral accounts are reasonable, and are approved. While the Commission approves the 2023 forecast NGSSC operating costs as reasonable, the Commission denies deferral account treatment for these costs for the reasons set out in Section 7.3.2.3. The Commission directs Apex to remove the NGSSC operating costs

from the O&M deferrals (A&G) expense account, as shown in Table 16 above, and reclassify these costs as general distribution operating costs. ........................ paragraph 234

17. Based on its assessment, the Commission is prepared to accept the 2021 non-audited actual costs as prudently incurred unless noted otherwise in this decision. This finding is also subject to the Commission's review of each utility's explanations for any variances between the non-audited 2021 actual expenditures filed in this proceeding in April 2022 and audited costs reported in 2021 Rule 005 filings. The Commission directs the utilities to file these explanations as part of their compliance filings to this decision....................... ......................................................................................................................... paragraph 239

18. The Commission finds that the 2023 forecast costs for those programs that were forecast mechanistically are reasonable and approves them as filed, subject to using the escalation factors approved in Section 5.2. Accordingly, the Commission directs ATCO Gas to provide updated amounts in the compliance filing. ...................................... paragraph 247

19. Finally, ATCO Electric explained that, as the managed service provider at the time of the CIS Replacement project, Wipro was required to perform work on the CIS project. In preparing the CIS Replacement project business case, ATCO Electric forecast Wipro services costs of $6.7 million using the Wipro rates set out in the Wipro Master Services Agreement (Wipro MSA). As such, ATCO Electric identified that a $1.8 million reduction to the cost of the Wipro services involved in the CIS Replacement project was required to comply with the pricing directed in Decision 20514-D02-2019 (the IT Common Matters decision). ATCO Electric confirmed that actual costs charged to the project for these services performed by Wipro used the prescribed IT Common Matters rates. ATCO Electric proposed to make the necessary adjustment to the approved 2023 revenue requirement at the time of the compliance filing. The Commission agrees and directs ATCO Electric to remove $1.8 million in capital additions for this project in its compliance filing. ............................................................................................ paragraph 281

20. The Commission finds that the 2023 forecast costs for those programs that were forecast mechanistically are reasonable and approves them as filed, subject to using the escalators approved in Section 5.2. Accordingly, the Commission directs Apex to provide updated amounts in the compliance filing. ................................................................... paragraph 287

21. The Commission directs Apex to remove the proposed $3.27 million of capital additions from its 2023 forecast revenue requirement in the compliance filing to this decision. ......................................................................................................................... paragraph 303

22. In addition, the ATCO Distribution Utilities provided no persuasive evidence that the IT rates with IBM/Kyndryl are just and reasonable. Based on the factors identified above, the Commission directs each of the ATCO Distribution utilities to reduce their 2023 IT managed services forecast costs by 15 per cent. In coming to this disallowance, the Commission reiterates that, unlike the Commission's concerns in the IT Common Matters decision about the shortcomings in the competitive procurement process employed by ATCO prior to selecting Wipro as its external managed IT services provider, here there was no competitive procurement process of any kind leading to the selection of IBM/Kyndryl. A 15 per cent reduction is appropriate in the circumstances of this case, given the paucity of relevant or compelling evidence to support the reasonableness of the IBM/Kyndryl rates. ........................................................................................ paragraph 389

23. The Commission agrees with J. Stephens' recommendation that the ATCO Distribution Utilities be required to provide similar detail to Table 4 of his evidence in a future rate or tariff application. The Commission considers that additional clarity around IT costs is necessary. The Commission therefore directs the ATCO Distribution Utilities to provide information on total IT expenditures, the MFR accounts in which these costs are recorded, an identification of all IT corporate costs and the method used to allocate IT costs to ATCO distribution and transmission utilities in future rate proceedings. ........................................................................................................................ paragraph 390

24. Throughout this decision, the Commission has issued various directions to ATCO Gas, ATCO Electric and Apex. The Commission directs each of ATCO Gas and Apex to file a compliance application to finalize their respective 2023 forecast revenue requirements to reflect the approvals, denials, and adjustments in this decision by October 3, 2022. ATCO Electric must reflect the adjustments from this decision in its September 26, 2022, compliance filing, directed by the Commission in Decision 26615-D01-2022. ........................................................................................................................ paragraph 405

25. To assist the Commission in reviewing the compliance of ATCO Gas and Apex with the directions in this decision, the Commission directs both utilities to support their revised 2023 revenue requirement, inclusive of 2023 forecasts, with accompanying Excel schedules. Specifically, each of the 2023 forecast amounts contained in the rebasing templates should either have a working formula showing how the number was determined (e.g., a formula that shows the calculation of the escalated 2018-2020 average), or reference to an associated working paper where such calculation was performed. The calculations should clearly illustrate how the utility's compliance with a Commission direction (e.g., denial of a capital project or the application of approved escalators) was achieved. ................................................................... paragraph 407