Decision **26615-D01-2022**

Alberta Utilities Commission

ATCO Electric Ltd.
FortisAlberta Inc.

2023 Cost-of-Service Review

July 28, 2022

Alberta Utilities Commission
Decision 26615-D01-2022
ATCO Electric Ltd.
FortisAlberta Inc.
2023 Cost-of-Service Review
Proceeding 26615

July 28, 2022

Published by the:
Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

Telephone: 310-4AUC (310-4282 in Alberta)
1-833-511-4AUC (1-833-511-4282 outside Alberta)
Email: info@auc.ab.ca
Website: www.auc.ab.ca

The Commission may, within 60 days of the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

Contents

List of tables

ATCO Electric Ltd.
FortisAlberta Inc. **Decision 26615-D01-2022**
2023 Cost-of-Service Review **Proceeding 26615**

1 Decision summary

1. This decision provides the Alberta Utilities Commission's determinations in respect of the 2023 cost-of-service (COS) applications from ATCO Electric Ltd. and FortisAlberta Inc. In reaching its decision the Commission has reviewed the 2023 forecast costs of ATCO Electric and Fortis that will underly 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 Electric and Fortis, 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 performance-based regulation (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. For the reasons set out in this decision, the Commission makes the following findings.

4. The Commission largely accepts the hybrid methodologies for forecasting 2023 costs put forward by ATCO Electric and Fortis, which use mechanistic and non-mechanistic approaches to arrive at their respective 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 escalation factors such as inflation and customer growth. Under the non-mechanistic approach, the utilities forecast from the bottom up, which is a traditional way to forecast costs under COS regulation.

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

- ATCO Electric is to use its actual labour cost increases for the period 2019-2020 in calculating its inflation escalator.

- Fortis is to remove the materials price escalator from its inflation escalator for capital costs.

- Both ATCO Electric and Fortis are to reduce their proposed customer growth escalator by 15 per cent.

6. The Commission directs each of ATCO Electric and Fortis to recalculate their respective 2023 forecasts under the mechanistic approach to reflect the escalation factors approved in this decision.[1] Further, the Commission directs Fortis to remove the customer growth escalator from the calculation of its unit prices for all of its capital additions where the forecast was obtained by multiplying the unit prices (calculated using the escalated 2018-2020 average) by the number of units (estimated from the bottom up).

7. As set out in the Commission's letter dated April 8, 2022, Information Technology (IT) and Customer Information System (CIS) costs will be addressed in the decision in Proceeding 26616 for both ATCO Electric and ATCO Gas North. As such, the disallowances set out below do not reflect any further adjustments that may be made to ATCO Electric's IT and CIS costs reviewed in that proceeding.

8. The Commission finds ATCO Electric's 2023 operating and maintenance (O&M) and capital additions forecast 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 Electric

Program	Disallowance	Amount ($ million)
O&M		
Overhead Line Expenses O&M account (USA 583)	Restructuring of the workforce	1.3[2]
Demand-side Management Program	Emissions Reduction and Energy Efficiency Program	0.885
Capital		
Line Rebuilds, Replacements and Life Extensions Program	Overhead Line Rebuilds, Replacements and Life Extensions (non-mechanistic)	8.918
General Support Program	Transportation Equipment (non-mechanistic)	4.527
Grid Modernization Program	ADMS project	2.95
Grid Modernization Program	Depreciation rates for meters	1.4
Total disallowances		**19.98**

9. The Commission finds Fortis's 2023 O&M forecast to be reasonable. The Commission also finds Fortis's 2023 capital additions forecast to be reasonable, subject to the incorporation of the approved escalation factors and the following capital disallowances:

Table 2. Capital disallowances for Fortis

Program	Disallowance	Amount ($ million)
Demand-side Management Program	Low-income Demand-side Management initiative and Customer Education and Awareness of Smart Services and Technology initiatives	2.0
Forestry Protection – Wildfire Mitigation	High-risk Fire Area Rebuilds	9.8

[1] As discussed in Section 9, Fortis is directed to update its summary table in IR response FAI-AUC-2022APR12-001 by reviewing each capital category and program and clearly identifying what forecasting methods it used.

[2] The precise amount of disallowance for this program may be affected by the Commission's findings on escalation factors. To clarify, ATCO Electric is to recalculate using approved escalators, and then reduce its request for additions by half.

Program	Disallowance	Amount ($ million)
System Purchases	Acquisition of Small Electricity Distribution Systems	15[3]
Secondary Upgrades	Single Service Upgrades and Secondary Network Upgrades	5.4
Remote Community Reliability	Full program	2.1
Total disallowances		**34.3**

10. In light of the foregoing, each of ATCO Electric and Fortis must submit a compliance filing by September 26, 2022, to reflect the directions and findings in this decision.

11. 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.

12. 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 provide 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.

13. The Commission wishes to emphasize that this decision only deals with distribution rates, and they are just one part of customer bills. In 2022, distribution charges are estimated to make up 45 per cent[4] and 32 per cent[5] of a typical residential bill for ATCO Electric and Fortis, respectively. Customer bills also contain electric transmission system charges, retailer administration fees, the retail price of the electricity the customer is consuming, franchise fees paid to the customer's municipality for utility access to its lands, and various Commission-approved riders that adjust bills for different reasons. The Commission has no oversight over the price of electricity, which is set in the deregulated electricity market, and exercises a more limited review of franchise fees, which are set by agreement between a municipality and the utility.[6]

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 are required to be specifically

3 Although the Commission denied Fortis's request for approval of $15 million, the Commission granted Fortis deferral account treatment for any system purchase transaction in 2023. Fortis will receive no revenue requirement upfront for these purchases, but will be able to true up actual costs incurred.

4 Proceeding 26849, ATCO Electric 2022 PBR Rates Application, Exhibit 26849-X0009, 2022 Rate Comparisons, tab Appendix H-1.

5 Proceeding 26817, Fortis 2022 Annual Rate Adjustment Filing, Exhibit 26817-X0026.01, Schedule 4.3 2022 Typical Bill Impacts by Rate Class, tab 11.

6 Franchise fees in the service areas of Fortis and ATCO Electric are typically imposed pursuant to agreements based on the templates approved by the Commission in decisions 2012-255 and 2012-294. The template franchise agreements permit the municipality to change the franchise fee once annually subject to a franchise fee cap of 20 per cent.

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).[7] 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 Ltd., FortisAlberta Inc., ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc.; and the two large natural gas DFOs in Alberta: ATCO Gas and Pipelines Ltd., and Apex Utilities Inc. (formerly AltaGas Utilities Inc.). This is the second PBR plan in Alberta for all of the DFOs, with the exception of ENMAX.[8] 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,[9] 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 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 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."[10] The rebasing process determines new rates that will be used for the next PBR term, referred to as "going-in rates."

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

8 ENMAX was under formula-based ratemaking (FBR, 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.

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

10 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).

18. On March 1, 2021, the Commission issued Bulletin 2021-04[11] 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,[12] the Commission found that, on balance, PBR achieved many of the objectives that were set out in the founding PBR principles.[13] 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 ATCO Electric and Fortis. In addition, this proceeding included an assessment of prudence of actual costs incurred to-date by the DFOs in the 2018-2022 PBR term.

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 O&M and administrative expenses of the company plus the utility's capital-related costs (depreciation, 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 (kW)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,[14] the Commission adopted a hybrid approach for the review and

---

[11] 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.

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

[13] Decision 26356-D01-2021, paragraph 82.

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

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 left it open to 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."[15]

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. ATCO Electric and Fortis were the first utilities to file their applications, followed one month later by ATCO Gas and Apex (Proceeding 26616), and two months later by ENMAX and EPCOR (Proceeding 26617).

26. To assist the utilities in preparing their applications, the Commission provided a rebasing template,[16] 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 O&M costs, capital costs, materiality thresholds, identification and quantification of efficiencies and disallowances, are described where applicable in the main body of this decision.

3 Applications summary

27. ATCO Electric and Fortis 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 Electric and Fortis employed a non-mechanistic or "bottom-up" approach.[17]

28. For its mechanistic approach, ATCO Electric 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 Electric's forecast inflation and annual customer growth rates for the 2021-2023 period. For accounts where ATCO Electric applied a mechanistic approach, its view was that the escalated 2018-2020 average is representative of

[15] Decision 26354-D01-2021, paragraph 27.
[16] Proceeding 26354, Post-disposition documentation, Appendix 2 - Final rebasing template - Electric, September 22, 2021.
[17] Exhibit 26615-X0023, ATCO Electric application, PDF page 47, paragraph 151.

costs reasonably anticipated to be incurred in 2023, and ATCO Electric did not expect these costs to fluctuate significantly from the costs incurred over the 2018-2020 period.[18]

29. Fortis also used a mechanistic approach for certain capital groupings. Fortis's mechanistic approach also used an escalated 2018-2020 average; however, Fortis used a slightly different methodology. Specifically, Fortis converted each of the 2018 to 2020 historical amounts to 2023 dollars normalized for inflation and system size using its chosen inflation and customer growth escalators (actual inflation and customer growth rates for the years 2018 to 2020 and forecast for the years 2021 to 2023) and then averaged the normalized 2018, 2019 and 2020 cost figures. While the order of steps taken by Fortis and ATCO Electric to escalate historical amounts were different, and the inputs to the formulas were different, these formulas are conceptually identical. The Commission will therefore refer to the results of both ATCO Electric's and Fortis's calculations as their "escalated 2018-2020 average."

30. Fortis and ATCO Electric relied on a non-mechanistic approach, or a "bottom-up" methodology, 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 Electric and Fortis 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 Electric 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 Electric submitted that this approach allowed it to account for trends in the Alberta economy and for COVID-19 by incorporating this historical data. A detailed list of forecasting methods (mechanistic and non-mechanistic) for each of ATCO Electric's cost categories is provided in Appendix 4. A summary of ATCO Electric's 2023 revenue requirement is shown below in Table 3.

Table 3. ATCO Electric's 2023 distribution revenue requirement

	($ million)
Return on Rate Base	170.64
Depreciation & Amortization	154.07
Operating & Maintenance Expenses	189.54
Revenue Offsets	(12.55)
Fuel and Non-Pool Energy	(2.88)
Income Tax Expense	(4.49)
Total	**494.33**

Source: Exhibit 26615-X0024, Schedule 1.0.

18 Exhibit 26615-X0023, ATCO Electric application, PDF page 16, paragraph 32 and Section 5.3.

32. ATCO Electric'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 Electric 2018-2023 summary of revenue requirement[19]

	2018 Actual	2019 Actual	2020 Actual	2021	2022 Forecast	2023 Forecast
	($000)					
O&M	169,086	155,673	185,571	184,826 (Actual)	N/A	189,543
Total revenue (PBR) or revenue requirement (2023)	392,929	418,567	421,498	460,378 (Forecast)	475,023	494,333

Note: The Commission used actual reported values for better comparability

33. In contrast to ATCO Electric, Fortis forecast all of its O&M and A&G costs using a non-mechanistic approach. Fortis forecast its 2023 capital additions using both non-mechanistic and mechanistic approaches. In addition, there are a number of capital programs that Fortis forecast by multiplying the unit prices (calculated using the escalated 2018-2020 average) by the number of units (estimated from the bottom up). A detailed list of forecasting methods (mechanistic and non-mechanistic) for Fortis's capital programs is provided in Appendix 5.[20]

34. A summary of Fortis's 2023 revenue requirement resulting from its forecast is shown below in Table 5.

Table 5. Fortis's 2023 distribution revenue requirement

	($ million)
Return on Rate Base	245.30
Depreciation & Amortization	274.90
Operating & Maintenance Expenses	230.80
Revenue Offsets	(93.90)
Income Tax Expense	14.30
Total	**$671.40**
Other Revenue Requirement Adjustments	
No Cost Capital	-
Y Factor Deferrals	(1.80)
Deferred Charges	0.10
Phase II Adjustment	(9.80)
Total	**$659.90**

Source: Exhibit 26615-X0033, Schedule 1.0

[19] 2018-2020 Actual O&M and 2022-2023 Forecast O&M: Exhibit 26615-X0024, Schedule 3.0, line 50; 2021 Actual O&M: ATCO Electric 2021 Rule 005 Filing, Schedule 1. Total Revenue (PBR) or Revenue Requirement – 2018-2020 Actual and 2023 Forecast: Exhibit 26615-X0024, Schedule 1.0, line 9; 2021 Forecast: Proceeding 25864, Post-disposition documentation, Appendix I, Schedule D.1, line 75, February 4, 2021. 2022 Forecast: Proceeding 26849, Exhibit 26849-X0010, Schedule D.1, line 67.

[20] As directed in Section 9, Fortis is directed to update this summary table by reviewing each capital category and program and clearly identifying what forecasting methods it used.

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

Table 6. Fortis 2018-2023 summary of revenue requirement[21]

	2018 Actual	2019 Actual	2020 Actual	2021	2022 Forecast	2023 Forecast
	($000)					
O&M	204,035	192,127	200,730	216,209 (Actual)	N/A	230,764
Total revenue (PBR) or revenue requirement (2023)	545,732	551,895	584,340	575,863 (Forecast)	621,473	659,869

Note: The Commission used actual reported values for better comparability

4 2023 forecast review and PBR3 rebasing

4.1 Commission's approach to reviewing the applications

36. In this section, the Commission explains its overall approach to reviewing the applications of ATCO Electric and Fortis. 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?

37. The Commission has a statutory mandate to set just and reasonable rates.[22] 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.[23] 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.[24]

38. 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

21 2018-2020 Actual O&M and 2022-2023 Forecast O&M: Exhibit 26615-X0033, Appendix A - 2023 COS Rebasing Template, Schedule 1.0. line 4. 2021 Actual O&M: Fortis Alberta 2021 Rule 005 Filing, schedule 1. Total Revenue (PBR) or Revenue Requirement – 2018-2020 Actual and 2023 Forecast: Exhibit 26615-X0033, Schedule 1.0, line 20; 2021 Forecast: Proceeding 25843, Exhibit 25843-X0003.01, Schedule 4.1. 2022 Forecast: Proceeding 26817, Exhibit 26817-X0025.01, Schedule 4.2, line 31.

22 *Electric Utilities Act*, Section 122.

23 *Northwestern Utilities Ltd. v Edmonton (City)*, [1929] S.C.R. 186.

24 See *Ontario v Ontario Power Generation*, 2015 SCC 44, paragraphs 15-18, where the court wrote that utilities must be given an opportunity recover their operating and capital costs over the long run. Under Section 122 of the *Electric Utilities Act,* this is referred to as a "reasonable opportunity to recover."

described by the Commission in its previous decisions.[25] 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.

39. In the current proceeding, the Commission is realigning revenues and costs for ATCO Electric and Fortis 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 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 Electric and Fortis) that were forecast mechanistically – that is, by escalating historical costs rather than by building the forecasts from the bottom up.

40. 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

41. 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.

42. 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.[26] This is because, unlike in a

[25] See for example Decision 2012-237, sections 1.1 and 1.2.
[26] Decision 20414-D01-2016 (Errata), paragraph 34.

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.[27] Parties expressed a similar view in this proceeding and the Commission continues to share this view.[28]

43. 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.[29] 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.[30] 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.[31]

44. 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.[32] In this proceeding, the interveners drew attention to this incentive and urged the Commission to ensure that the sharing of benefits as a result of realigning costs and revenues is not eliminated as a result of utilities over-forecasting to offset, or deny, the benefit to consumers of efficiencies realized in the previous PBR term. Given that sharing of benefits of a PBR plan between customers and utilities is one of the Commission's founding PBR principles[33] 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."[34]

45. In this regard, the interveners representing customer groups in this proceeding (Consumers' Coalition of Alberta (CCA), Industrial Power Consumers Association of Alberta (IPCAA) and the Office of the Utilities Consumer Advocate (UCA)) advocated that the Commission adopt some elements of the PBR2 rebasing approach approved in Decision 20414-D01-2016 (Errata). Specifically, they favoured rebasing based on the lowest cost year approach

27 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.

28 Exhibit 26615-X0177, AE-AUC-2022JAN14-009(c); Exhibit 26615-X0201, FAI-AUC-2022JAN14-003(i); Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraph 161; Exhibit 26615-X0476, UCA oral argument, paragraph 57.

29 Decision 2012-237, paragraph 759.

30 Decision 20414-D01-2016 (Errata), paragraph 45.

31 Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraphs 176-180, referencing the Commission's past PBR-related decisions.

32 Decision 20414-D01-2016 (Errata), paragraph 43.

33 The AUC five PBR principles are set out in paragraph 28 of Decision 2012-237.

34 Decision 26354-D01-2021, paragraph 40.

which, in their view, ensures that customers benefit from the efficiencies achieved during the prior PBR term. 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?

46. 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.

47. 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 the onus of demonstrating and supporting the reasonableness of the elements comprising its revenue requirement.[35]

48. 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 5.1.2 of this decision, this is not the case for either ATCO Electric or Fortis as they earned more than their approved ROE in most years of the PBR2 term.

49. In addition, 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.

50. 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.

51. 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

[35] Decision 26354-D01-2021, paragraph 13.

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

52. In the notice of application issued on November 16, 2021,[36] 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.

53. 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.[37] In this proceeding, the Commission asked parties whether the 2023 actual closing rate 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.[38]

54. ATCO Electric and Fortis suggested that the Commission should defer its consideration of this issue to the proceeding setting the parameters of the PBR3 plans. ATCO Electric did express some support for using actual 2023 closing rate base, noting that using actual closing rate base could address forecast risk in uncertain times and could be fair to both the utility and the utility's customers.[39] In contrast, Fortis noted that "any decision to adopt a rate base true-up approach will necessarily push final rate base and revenue requirement determinations and associated processes into future periods."[40]

55. 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.[41]

56. IPCAA proposed that the method to establish going-in rates should be based on the 2023 actual closing rate base for the commencement of PBR3 in 2024.[42] However, IPCAA later clarified that the UCA's concerns regarding timing were valid and stated that using the approved forecast rate base approach would also be acceptable.[43]

---

36 Exhibit 26615-X0055, Notice of application, 2023 Cost-of-service review.
37 Decision 26354-D01-2021, paragraph 25.
38 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.
39 Transcript, Volume 5, page 727, lines 9-13 (L. Smith).
40 Transcript, Volume 5, pages 661-662 (B. Hunter).
41 Transcript, Volume 5, page 817.
42 Transcript, Volume 5, page 828.
43 Transcript, Volume 5, page 832.

57. 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 Electric and Fortis's going-in rates for PBR3 in 2024.

58. 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 Electric and Fortis, and would therefore extend the final determination of the going-in rates for their PBR plans until well into 2024.

59. 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 Electric and Fortis 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 eliminating avoidable retrospective adjustments to rate base, which may be detrimental to both the utilities and their customers.

60. 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.

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

62. 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.

63. 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.

64. 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 Fortis and ATCO Electric

5.1 Identification and quantification of efficiencies

65. 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 quantified the achieved efficiencies in their applications. Next, alternative proposals to the quantification of efficiencies presented by the interveners are discussed. 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

66. The identification and quantification of efficiencies achieved by ATCO Electric and Fortis during the 2018-2022 PBR 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.[44]

67. Specifically, the Commission opted not to include in the PBR2 plan (and the PBR1 plan before it) an earnings-sharing mechanism (ESM).[45] The Commission noted that during the PBR term, customers automatically share in the expected efficiency gains because these are built into rates through the X factor (inclusive of the stretch factor) regardless of the actual performance of a utility.[46] 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.[47] The interveners in this proceeding pointed out 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.

68. 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 found, and cost reductions achieved, during the PBR2 term are reflected in their forecast revenue requirement and will be passed on to customers.

---

44 Decision 2012-237, paragraph 28.
45 The Commission notes that this decision does not preclude the consideration of introducing an ESM in PBR3. See Proceeding 27388, Exhibit 27388-X0020, AUC letter - Preliminary list of issues and directions on procedure.
46 Decision 2012-237, paragraph 17.
47 Decision 20414-D01-2016 (Errata), paragraph 26.

5.1.2 How the utilities quantified the achieved efficiencies

69. The Commission has previously concluded that PBR plans to date have incented Fortis and ATCO Electric to find efficiencies in service delivery to maximize their profits, similar to what should be experienced in a competitive market.[48] The Commission heard evidence in this proceeding to support this conclusion.

70. Fortis and ATCO Electric identified some initiatives that resulted in efficiencies (as further explained in this section), and quantified the most important efficiencies gained through these initiatives. As set out in Table 7 below, Fortis and ATCO Electric both earned more than the approved ROE set by the Commission in three of the 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 ROE can be attributed to efficiencies, they acknowledged that achieved ROE is a key indicator of whether or not efficiencies were achieved.[49] Fortis offered the further qualification that the achieved ROE does not, in itself, aid in identifying and quantifying efficiencies.[50]

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
Fortis	8.43	10.14	10.13	10.23	Will be available on May 1, 2023, as part of Rule 005[51] filing
ATCO Electric	11.15	8.34	9.82	12.85	Will be available on May 1, 2023, as part of Rule 005 filing

71. Fortis identified 12 programs[52] where it "leveraged technology and other forms of innovation to improve productivity during the current PBR term"[53] to achieve certain efficiencies. Fortis submitted that these 12 programs resulted in an approximate reduction of $14 million in costs, and that this reduction has been embedded in the 2023 COS application.

72. In its application, ATCO Electric provided examples of a number of programs or initiatives in which efforts were undertaken to improve efficiency during the PBR2 term.[54] ATCO Electric also offered a high-level calculation of the efficiencies achieved in the PBR2 term. In response to a Commission IR, ATCO Electric indicated that its 2023 COS forecast is $48.5 million lower than the revenue that would have been received under PBR rates had the PBR2 plan continued in 2023.[55] In its rebuttal evidence, ATCO Electric explained that its 2023

48 Decision 26356-D01-2021, paragraph 11.
49 Transcript, Volume 1, page 92; Transcript, Volume 2, pages 318-319; Transcript, Volume 3, page 451.
50 Exhibit 26615-X0031, Fortis application, paragraph 111.
51 Rule 005: *Annual Reporting Requirements of Financial and Operational Results.*
52 Exhibit 26615-X0031, Fortis application, Section 2.6.2.
53 Exhibit 26615-X0201, FAI-AUC-2022JAN14-001.
54 Exhibit 26615-X0023, ATCO Electric application, Section 8.
55 Exhibit 26615-X0177, Table 1, PDF page 9 (excluding distribution to transmission contributions).

COS forecast is $16 million lower than the revenue expected to be received in 2022 under the approved PBR rates.[56]

73. Both utilities explained that while the efficiencies they were able to quantify comprise the majority of those realized during the PBR2 term, they do not represent the entirety of their achieved efficiencies because there are likely other efficiencies that have been achieved but that have not been explicitly quantified. Both utilities contended that, ultimately, all of their achieved efficiencies are embedded in historical costs, which in turn form the basis or the starting point for the 2023 forecast revenue requirement.[57]

74. Based on this, Fortis and ATCO Electric argued that their use of a hybrid methodology in determining their 2023 forecast embedded all efficiencies achieved, both quantified and non-quantified. Specifically, costs forecast under the mechanistic approach using the historical actual average costs for 2018-2020 (the first three years of the PBR2 term) reflect actual costs and efficiencies that resulted in cost savings in those years. Costs forecast under the non-mechanistic approach for a program also reflect a utility's ability to deliver that program, considering all of the efficiencies achieved to date.

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 PBR. Dustin Madsen for IPCAA and Jan Thygesen for the CCA stated that the applied-for forecasts have largely offset the efficiencies gained. Russ Bell for the UCA stated that the "use of a 3-year average masks and holds benefits back from customers."[58] The interveners offered the following two remedies to address their concerns: (i) return to customers any earnings above the approved ROE; and (ii) use the lowest cost year as a basis for 2023 forecasts. Each of these proposals is discussed below.

5.1.4 Earnings above the approved ROE

76. IPCAA[59] and the CCA[60] proposed that any earnings in excess of the approved ROE must be passed on to customers in their entirety because, in their view, such earnings reasonably approximate the achieved efficiencies and associated cost savings. The Commission does not find that this proposal is reasonable for the reasons that follow.

77. First, the Commission agrees with Fortis that achieved ROEs are not driven entirely by efficiencies. In this proceeding, Fortis explained that "achieved ROEs result from a combination of several factors, including weather related impacts on energy deliveries, actual experienced

[56] Exhibit 26615-X0414, Table 5, PDF page 25.
[57] Transcript, Volume 1, page 74 (B. Henderson); Transcript, Volume 3, pages 362-363 (M. Bayley).
[58] Exhibit 26615-X0328, UCA evidence (redacted), PDF page 17.
[59] While IPCCA's expert, D. Madsen, used average annual earnings above the approved ROE as a reasonableness check against his recommended adjustments to the utilities' forecasts (Exhibit 26615-X0298, IPCAA evidence of D. Madsen, PDF page 25), IPCAA in its argument stated that its "approach to quantifying efficiencies from the perspective of broad-based gains and net earnings represent a reasonable proxy to the efficiencies achieved by the utilities." (Transcript, Volume 5, page 826).
[60] Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraph 4.

billing determinants, the timing and the associated recognition of recoverable amounts related to Commission decisions, and the structure and parameters of the PBR plan in force at the time."[61] 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.[62]

78. Second, the Commission agrees with ATCO Electric's view that such proposal effectively implements 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.

79. Third, the Commission previously explained that a PBR plan must be viewed and considered as a whole and that all of the elements of the plan must be considered together.[63] 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, may have a deleterious effect on the utilities' incentives to reduce costs, among other unintended effects.

80. 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 interveners proposed what could amount to the retroactive confiscation of earnings above the approved return without addressing any such considerations. The CCA drew parallels with the efficiency carryover mechanism (ECM)[64] (a mechanism 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); however, that parameter is an approved part of the PBR2 plan. Utilities and consumers knew in advance that the ECM was a component of the PBR plan. Further the ECM has a cap of 50 basis points. Thus, the concerns expressed above regarding the after-the-fact introduction of an ESM do not apply to the ECM.

5.1.5 Lowest cost year as a basis for 2023 forecasts

81. R. Bell for the UCA stated that, particularly for O&M, the use of the lowest cost year is the best proxy for calculating achieved efficiencies.[65] J. Thygesen for the CCA proposed to use the lowest cost year as a basis for 2023 forecasts for both O&M and capital costs.[66] D. Madsen for IPCAA recommended that O&M costs for both ATCO Electric and Fortis be calculated based on 2020 actual costs, escalated by the average of the approved I-X index.[67]

82. As pointed out by the interveners, the Commission adopted the lowest O&M cost approach in the rebasing process for the PBR2 term;[68] however, the use of the lowest cost year method in the present rebasing proceeding requires careful consideration. On the one hand, the

[61] Exhibit 26615-X0416, Fortis rebuttal evidence, paragraph 8.
[62] Decision 26356-D01-2021, paragraphs 25-26.
[63] Decision 20414-D01-2016 (Errata), paragraph 25.
[64] Transcript, Volume 5, pages 761-765 (CCA argument, J. Wachowich).
[65] Exhibit 26615-X0328, UCA evidence (redacted), PDF page 17.
[66] Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraph 43.
[67] Exhibit 26615-X0298, IPCAA evidence of D. Madsen, PDF pages 29-30 and 42-44.
[68] Decision 20414-D01-2016 (Errata), paragraph 52.

Commission agrees with the views of the utilities that a wholesale adoption of the lowest O&M cost year as an alternative rebasing methodology, as proposed by R. Bell and J. Thygesen, 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.[69] The Commission recognized the value of comparing the 2023 forecast costs to the lowest cost year (for both O&M and capital) when it requested that the utilities provide this information as part of their rebasing applications.[70]

83. 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. Given this, basing the 2023 forecast on actual experienced costs is an effective way to ensure that efficiencies are passed on to customers. While the interveners 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 Fortis and ATCO Electric of a 2018-2020 average of historical actual costs incurred during the PBR2 term and finds that this average reflects achieved efficiencies during that period.

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

85. 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 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 the lowest cost year.[71] In the PBR2 rebasing this necessitated the consideration of these events resulting in considerable regulatory burden.[72] In his evidence for IPCAA, D. Madsen considered adjustments to some O&M cost categories in his chosen base year to ensure costs are "representative of the ordinary costs." Notably, D. Madsen did not consider any such adjustments when recommending the use of the 2018-2020 average for capital costs.[73]

69 Decision 26354-D01-2021, paragraph 41.
70 Decision 26354-D01-2021, paragraphs 21 and 31.
71 Exhibit 26615-X0416, Fortis rebuttal, paragraph 15.
72 Decision 24325-D01-2020: Second Stage Review Proceeding to Consider the Concepts and Principles of an Anomaly Adjustment Review of Decision 22394-D01-2018 Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities First Compliance Proceeding, Proceeding 24325, January 30, 2020; Decision 25422-D01-2020: Anomaly Adjustment Applications in Rebasing the 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 25422, November 3, 2020.
73 Exhibit 26615-X0298, IPCAA evidence of D. Madsen, PDF pages 28-29 and 42.

86. Having determined that using the 2018-2020 average of historical costs is acceptable, the Commission also reviewed Fortis's and ATCO Electric'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 chosen escalation factors. The same escalated 2018-2020 average costs were also used by each of ATCO Electric and Fortis 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 some 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.

87. For costs forecast using a non-mechanistic approach, the Commission will compare the 2023 forecasts to the escalated 2018-2020 average. Both ATCO Electric and Fortis undertook a similar analysis in their applications. The Commission will also rely on efficiencies reported by the utility for a particular program, where applicable.

5.1.6 Measuring efficiencies in PBR3

88. During the oral hearing in April and May 2022, the Commission questioned ATCO Electric and Fortis 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 an electric distribution utility. The record of this proceeding suggests that ATCO Electric and Fortis either have yet to develop a standardized suite of metrics to identify, measure and track improvements in the productivity of their businesses over time or that they were reluctant to rely on such metrics for the purposes of quantifying efficiencies. As well, the debate on the most appropriate measure of output for an electric distribution utility appears to be unsettled, and will require additional work going forward.[74]

89. 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. Fortis questioned whether it is valuable to customers to "spend the money in order to prove that we've saved it …"[75] Ultimately, both ATCO Electric and Fortis 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

[74] Decision 20414-D01-2016, Section 5.2.4; Transcript, Volume 3, page 380 (M. Bayley); Transcript, Volume 4, page 598 (M. Bayley).
[75] Transcript, Volume 1, page 91, lines 2-19 (A. Johnson).

they are unable to assess potential efficiency gains at the project approval stage and subsequently track whether these efficiencies were realized.

90. However, what is clear from the record of this proceeding is that neither Fortis nor ATCO Electric have a documented process to which they could point in evidence, for tracking whether the projected efficiencies or cost savings associated with a particular initiative were indeed realized. R. Tisdale indicated that Fortis does not currently have a "fully mature benefits realization process."[76] 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.

91. To avoid similar challenges in identifying the achieved efficiencies and calculating the realized savings at the next rebasing, the Commission directs Fortis and ATCO Electric 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. Fortis provided examples of some possible forward-looking productivity and/or efficiency measures, including: (i) controllable O&M per customer; (ii) controllable O&M per employee; (iii) controllable O&M per kilometre (km) of distribution line; (iv) controllable O&M per unit of energy consumed; (v) controllable O&M per demand; and (vi) total cost per km of distribution line and annual maximum capacity.[77] ATCO Electric offered O&M per km of line as a possible measure, but also stated that it is important to not forget about service quality measures.[78]

5.2 Escalation factors

92. Fortis and ATCO Electric used escalation factors in two ways. First, escalation factors were used to simplify variance explanations for 2023 costs forecast under the non-mechanistic (bottom-up) approach. Both utilities generally adjusted their historical actual costs by inflation (including labour costs) and customer growth and compared their 2023 forecasts to the escalated historical numbers.[79] 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.

93. The reasonableness of 2023 revenue requirement forecasts contained in the rebasing applications are dependent in large part on the reasonableness of the escalation factors used by

[76] Transcript, Volume 1, page 80, lines 1-9 (R. Tisdale).
[77] Exhibit 26615-X0460, Fortis undertaking responses, PDF pages 5-8.
[78] Transcript, Volume 3, pages 379-381 (M. Bayley).
[79] In Exhibit 26615-X0031, Fortis application, paragraph 276, Fortis explained "the need to explain cost increases associated with customer additions growth, CPI, materials prices, and salary adjustments undertaken in the PBR incentivized environment, is eliminated through the use of this approach, since the contribution(s) of each of these factors is incorporated in the escalation adjustment."

each of the utilities. The Commission has therefore carefully reviewed the escalation factors used by both utilities as the basis for their 2023 forecasts. Although Fortis and ATCO Electric took similar approaches to their use of their chosen escalation factors, their escalation factors differ in several ways. Accordingly, in this section the Commission explains the escalation factors adopted by Fortis and ATCO Electric and how they compare to each other. The Commission then makes findings on the adoption of escalation factors and 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 Electric and Fortis

94. ATCO Electric used the same escalation factor for O&M and capital additions. It had two components: inflation and customer growth. Fortis used a similar methodology to ATCO Electric for calculating the inflation and customer growth escalation factors, albeit with some variation, for its O&M costs. Fortis incorporated an additional materials prices escalation factor for its capital costs, but otherwise used comparable inflation and similarly derived customer growth escalation factors for its O&M costs as ATCO Electric. Table 8 below summarizes the escalation factors used by the two utilities.

Table 8. Escalation factors used by ATCO Electric and Fortis

	2019	2020	2021	2022	2023
	(%)				
ATCO Electric[80]					
Inflation (O&M and capital)	1.58	2.27	2.76	3.18	2.68
Customer Growth	0.49	0.17	0.14	0.26	0.30
Fortis[81]					
Inflation – O&M	2.03	2.21	1.75	2.91	2.67
Inflation – Capital	1.85	1.57	7.81	11.19	2.80
Customer growth	1.11	0.80	0.95	1.16	1.20

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

95. 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 the components of the utilities' escalation methodologies in turn.

5.2.2 Inflation escalator

96. ATCO Electric's 2014-2020 inflation rates 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 Alberta weekly earnings (AWE), weighted at 45 per cent and 55 per cent, respectively. However, ATCO Electric

80 Exhibit 26615-X0025, 2014-2020 Inflation and Annual Growth Rate Calculations, for 2019-2020 values and Exhibit 26615-X0412, Table 19, PDF page 25 for 2021-2023 values.
81 Exhibit 26615-X0422, Preliminary (non-audited) 2021 actuals, PDF pages 18-19.

calculated the inflation escalator on a calendar year basis, rather than the July-to-June basis as is used for the I factor.

97. For the 2021-2023 CPI amounts, ATCO Electric relied on forecasts published by reputable third-parties (later updated to reflect the 2021 actual CPI).[82] For the 2021-2023 labour amounts, ATCO Electric used the weighted average of forecast salary escalation rates for its union and non-union employees. This is discussed in greater detail in Section 5.3. Table 9 summarizes ATCO Electric's inflation escalator calculations.[83]

Table 9. Calculation of ATCO Electric'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)	2.44 (68/32 Union/Non-union weighted)	2.48 (68/32 Union/Non-union weighted)	2.75 (68/32 Union/Non-union weighted)
45/55 CPI/Labour weighted	**1.58**	**2.27**	**2.76**	**3.18**	**2.68**

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

98. Fortis applied different escalators to its O&M and capital costs. For O&M, similar to ATCO Electric, Fortis used average annual Alberta CPI and labour costs using the I factor weightings from the prior PBR terms to arrive at its inflation escalator. A key difference compared to ATCO Electric is that for the 2014-2020 labour costs, Fortis did not use AWE. Instead, it used a weighted average of actual salary increases for union and non-union employees, which was intended to reflect its actual experienced costs. Fortis used forecast inflation and labour costs for the 2021-2023 period. Fortis also used a calendar year-based CPI and internal labour data.

99. For its capital costs, Fortis indicated that it was important to include the effects of inflationary pressure on materials prices that it experienced, or projected to experience, in 2021 and 2022. Fortis stated that materials costs represent, on average, 35 per cent of its total capital expenditures and have generally trended with Alberta CPI in the past. However, in 2021 and 2022, Fortis forecast significantly higher increases in materials costs. Fortis indicated that this was due to backlogs and bottlenecks associated with raw materials supply which caused constraints in manufacturing capacity, which in turn caused significant shortages relative to demand. Consequently, Fortis stated that finished goods lead times have significantly increased, along with prices. It anticipated these trends and the associated cost impacts to continue until the end of 2022.[84]

100. Fortis stated that its 2021 materials price forecast was based on the weighted average of actual materials price increases experienced during the first nine months of 2021, calculated as 12.46 per cent. Fortis later updated this number to 18.11 per cent as part of its 2021 non-audited

[82] Exhibit 26615-X0023, ATCO Electric application, Table 6; updated in Exhibit 26615-X0412, ATCO Electric 2021 preliminary (unaudited) actuals.

[83] Exhibit 26615-X0025, 2014-2020 Inflation and Annual Growth Rate Calculations, for 2019-2020 values and Exhibit 26615-X0412, Table 19, PDF page 25 for 2021-2023 values.

[84] Exhibit 26615-X0031, Fortis application, paragraph 279.

actuals update. Its 2022 forecast was based on a weighted probability of a range of forecast price increases, calculated as 17.55 per cent. This forecast was later updated to 25.83 per cent. Fortis further rationalized its incorporation of elevated materials prices in its inflation escalation factor for its capital costs in 2021 and 2022 because "its specialized materials, such as transformers, poles and conductor, are not included in the eight major components that drive the CPI basket."[85]

101. Fortis's calculations are summarized in Table 10.

Table 10. Calculation of Fortis's inflation escalator[86]

	2019	2020	2021	2022	2023
	(%)				
Alberta CPI	1.73	1.11	3.20	4.04	2.89
Materials cost escalator	1.73	1.11	18.11	25.83	2.89
Labour cost escalator	2.27	3.11	0.57	1.98	2.50
O&M inflation escalator: 45/55 CPI/Labour weighted	**2.03**	**2.21**	**1.75**	**2.91**	**2.67**
Capital inflation escalator: 42/35/23 CPI/Materials/Internal Labour weighted	**1.85**	**1.57**	**7.81**	**11.19**	**2.80**

Note :The table reflects the updated 2021-2023 CPI values and the updated applied-for materials index.

102. Subject to the modifications directed below, the Commission considers that the approaches of both of ATCO Electric and Fortis for estimating 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 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.[87] The interveners generally agreed with using some measure of inflation to adjust historical actual costs.[88]

103. Both ATCO Electric and Fortis relied on the same weightings between CPI and labour costs currently established for the I factor. Both used reliable data 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

85 Exhibit 26615-X0201, FAI-AUC-2022JAN14-004(a), PDF page 19.
86 Exhibit 26615-X0422, PDF pages 24-25.
87 Decision 2012-237, paragraph 228.
88 Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraphs 112 and 117; Exhibit 26615-X0364, IPCAA-AUC-2022MAR14-002(f); Exhibit 26615-X0391, CCA-AUC-2022MAR28-001, PDF page 4; Exhibit 26615-X0410, UCA-AUC-2022MAR14-002(f).

up-to-date data,[89] the Commission directs ATCO Electric and Fortis to use the 2021-2023 CPI values as shown in tables 9 and 10 above in their respective compliance filings.

104. Regarding labour costs, ATCO Electric used the Alberta AWE index as a substitute for its labour costs escalator for 2019 and 2020, and used its own actual or projected labour cost increases for 2021-2023. The Commission finds Fortis's approach of using its own actual or forecast labour cost growth for the entire 2019-2023 period to be more methodologically sound than ATCO Electric's approach because it uses the same data for both historical and forecast costs. The Commission considers the use of the utilities' actual and forecast labour costs is reasonable because the objective of this proceeding is to realign the utility's costs with prices. Further, in Section 5.3 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 Electric to recalculate the 2019-2020 inflation index based its own labour cost data using the same methodology used for developing its 2021-2023 labour cost indexes as shown in Table 9 above.[90]

105. The Commission denies Fortis's incorporation of elevated materials prices in its inflation escalation factor for its capital costs in 2021 and 2022. Fortis acknowledged that in the past materials prices have generally trended with Alberta CPI.[91] The Commission acknowledges that materials prices in 2021 and 2022 may have been elevated compared to historical prices, and may have trended higher than Alberta CPI, which has also been elevated through 2022. However, Fortis has not established that materials prices will remain elevated or continue to be delinked from Alberta CPI. Fortis's use of the 18.11 and 25.83 per cent increase for materials prices in 2021 and 2022 inflates historical prices to this level on a non-transitory basis.[92] This would suggest that the current elevated nature of materials prices would persist throughout the PBR3 term, which the Commission is not satisfied, based on the evidence before it, is the case.

106. The Commission paired ATCO Electric and Fortis in the present proceeding to allow for comparison between the two utilities. The Commission finds it significant that in this proceeding, ATCO Electric, a distribution utility that faces the same or very similar challenges in managing the costs of the materials used in operations, did not apply for a similar materials price adjustment and stated "ATCO Electric considers it reasonable to utilize an Alberta inflation index, such as the All-Items Alberta Consumer Price Index (CPI), for the purpose of historic cost indexing in a streamlined COS proceeding."[93] During the oral hearing both utilities discussed measures they are taking to mitigate the supply chain issues for materials used in their operations.[94]

89 Exhibit 26615-X0411, AUC letter - Clarification on April 1 filing and ATCO Electric request to change process and schedule, paragraph 10.
90 ATCO Electric provided its actual labour cost inflation in Exhibit 26615-X0414, ATCO rebuttal evidence, Table 1, page 7.
91 Exhibit 26615-X0031, Fortis application, paragraph 279.
92 Exhibit 26615-X0033, Fortis rebasing template, Sch WP1, row 33.
93 Exhibit 26615-X0414, ATCO Electric rebuttal evidence, paragraph 8.
94 Transcript, Volume 1, pages 135-138 (B. Henderson), Transcript, Volume 3, page 395 (G. Hari), Transcript, Volume 4, page 590 (G. Hari).

107. For the reasons above, the Commission directs Fortis to remove the separate materials price component from its capital inflation escalator calculation.

108. The Commission notes that its acceptance of ATCO Electric's and Fortis'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

109. Both ATCO Electric and Fortis calculated their customer additions growth escalators as the year-over-year change in the number of customer sites each utility serves.[95] Actual site count values were used for years 2018-2019, and forecast values were used for 2021-2023. These escalators are shown in Table 8 above.

110. 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. In addition, the Commission discusses whether it is appropriate for Fortis to use the customer growth escalator to escalate unit-costs in non-mechanistic forecasts.

5.2.4 Whether applying a customer growth escalator is reasonable

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

112. Interveners expressed concern with the use of a customer growth escalator. They stated that the utilities filed no evidence showing that the variation from year to year in historical actual costs can be explained by the escalation factors they proposed to use. J. Thygesen, on behalf of the CCA, contended that the use of the customer growth escalator results in double counting because historical dollars already reflect customer growth. Both of these assertions imply that the utilities' use of customer growth as an escalation factor overstates the resulting 2023 cost forecast.

113. ATCO Electric and Fortis pointed to a footnote in Decision 26354-D01-2021 which lists customer growth as a potential escalator,[96] as a partial justification for relying on their choice of customer growth escalation factor. However, in oral argument, ATCO Electric acknowledged that this footnote does not presumptively approve any specific escalator; nor does it remove the burden from the utilities to demonstrate that their forecasts are reasonable.[97]

---

95 Exhibit 26615-X0031, Fortis application, paragraph 143; Exhibit 26615-X0023, ATCO Electric application, paragraphs 56-59.
96 Decision 26354-D01-2021, footnote 3.
97 Transcript, Volume 6, page 863 (L. Smith).

114. The Commission sees merit in adjusting historical costs to account for growth of the utilities' distribution systems over time. Fortis indicated that it added 30,000 customers between 2018 and 2023 or 80,000 customers over the last 10 years.[98] In the Commission's view, the total costs associated with providing electric distribution service in 2023 can reasonably be assumed to be higher than costs for the system in 2018 when it had 30,000 fewer customers.

115. The Commission was also persuaded that a volume adjustment is required to account for the increased costs of providing electric distribution service to more customers and to compare years on a consistent basis. ATCO Electric explained that a customer growth escalation factor recognizes that, as a distribution system grows (to serve new customers or to accommodate growth of existing customers), capital additions are required to connect the customers and operating and maintenance costs to service assets will increase. Therefore, it is necessary to account for system size changes (growth escalator) from year to year to in order to equate dollars from one year to the next.[99] The Commission agrees with ATCO Electric and Fortis 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

116. Having decided that a customer growth escalator is reasonable, the Commission must now decide whether the specific customer growth escalators used by ATCO Electric and Fortis are reasonable.

117. Both ATCO Electric and Fortis proposed customer growth escalators that moved in lockstep with the actual or forecast year-over-year change in the number of customer sites on their respective distribution systems. If, for example, ATCO Electric or Fortis experienced 1.5 per cent growth in new customer sites in a given year, then their customer growth escalator would be 1.5 per cent.

118. 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 Fortis and ATCO Electric 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.[100] However, the record of this proceeding challenges that assumption.

119. The Commission did not observe that there was a one-to-one relationship between customer growth and the utilities' O&M and capital costs. During the hearing, ATCO Electric and Fortis acknowledged that while the total number of customers they serve increased over time, their O&M and capital costs did not change in lockstep with customer growth. This was

98 Transcript, Volume 2, page 198 (B. Henderson).
99 Exhibit 26615-X0414, ATCO Electric rebuttal evidence, paragraph 38.
100 Transcript, Volume 3, page 412 (C. Severson).

demonstrated for several of each utility's O&M and capital categories, which showed that actual costs are driven by a multitude of factors, of which customer growth is just one.[101]

120. Fortis and ATCO Electric tried to explain this discrepancy but their explanations did not persuade the Commission that their proposed customer growth escalators were appropriate. Fortis explained that one contributing factor for customer growth not tracking costs is that there is a lag between when a utility makes expenditures to connect a customer and when the customer is actually energized and becomes billable (i.e., counts as a customer site).[102] ATCO Electric indicated that customer growth is "a long run driver of cost, which is related to the size of the system"[103] implying there may be a mismatch in the shorter term.

121. 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. ATCO Electric acknowledged that the larger a utility is, the more opportunities there are for economies of scale.[104] This is consistent with conventional economic theory. 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.

122. 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 measurements for the purpose of measuring or tracking 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 Electric or Fortis.

123. As stated at the outset of this section, the reasonableness of 2023 revenue requirement forecasts contained in the rebasing applications are dependent 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 finds that a downward adjustment to the customer growth escalators proposed by Fortis and ATCO Electric is required.

124. As a result, the Commission finds that there is a need to introduce an offset to the customer growth escalation factors used by both utilities to account for its observations 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

[101] Transcript, Volume 2, page 215 (Fortis), Transcript, Volume 3, pages 413-417 (ATCO Electric).
[102] Transcript, Volume 1, page 116 (A. Johnson).
[103] Transcript, Volume 4, page 560 (M. Bayley).
[104] Transcript, Volume 4, pages 562-563 (M. Bayley).

Commission directs each of the utilities to reduce their proposed customer growth escalation factors by 15 per cent.[105]

125. Overall, the Commission agrees with ATCO Electric's view[106] that while not a perfect proxy, the customer growth escalation factor, as adjusted by the Commission, allows for a reasonable approximation of utility costs as an alternative to a line-by-line COS review. It strikes a reasonable balance among the following objectives: (i) achieving the requisite level of precision in determining the 2023 revenue requirement; (ii) reducing regulatory burden as part of streamlined review process; and (iii) ensuring that efficiencies achieved during the PBR2 term are passed on to customers.

126. 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 year-over-year comparisons on a consistent basis and over the long term.

5.2.6 Issues with Fortis's application of the customer growth escalator

127. Fortis forecast certain capital, such as the Customer Growth capital grouping, using a non-mechanistic method that multiplied the unit prices (calculated using the escalated 2018-2020 average) by the number of units (estimated from the bottom up).

128. The Commission finds that using the customer growth escalator to generate unit price forecasts is not reasonable because, as explained above, this escalator relates to the adjustment of volumes, not prices. For capital additions where Fortis used a bottom-up forecast based on a specific number of units or volume of work, there is no need for a separate customer growth escalator to escalate unit prices. The Commission directs Fortis to remove the customer growth escalator from the calculation of its unit prices for all of its capital additions where the forecast was obtained by multiplying the unit prices (calculated using the escalated 2018-2020 average) by the number of units (estimated from the bottom up).

5.3 Forecast labour escalations for both Fortis and ATCO Electric

129. Both Fortis and ATCO Electric forecast salary escalations for 2023. Fortis applied for an overall organizational salary adjustment of 2.5 per cent to all forecast full-time equivalents (FTEs) in 2023.[107] ATCO Electric applied for a 3.5 per cent increase for non-union employees[108] and a 2.4 per cent increase for union employees in 2023. ATCO Electric and Fortis each engaged Mercer (Canada) Limited to provide evidence to support these salary escalation requests. Fortis also retained and filed information prepared by Willis Towers Watson regarding non-union salary budget projections for 2022 and 2023.

[105] That is, when escalating historical costs, the utilities will use a formula (1+Inflation) x (1+Customer Growth*0.85).

[106] Transcript, Volume 4, pages 568-569.

[107] Exhibit 26615-X0031, Fortis application, paragraph 170.

[108] Members of the United Workers Association are designated as "association" or "in-scope" employees, whereas non-association members are designated as "out of scope" employees.

130. For Fortis's non-union compensation assessment, Mercer compared 239 (or 97 per cent) of Fortis's non-union positions against similar positions within a comparator group. The comparator group consisted of 25 companies in related industries, located in the same geographic region, and being of similar size and complexity. In general, the comparator group consisted of Canadian gas and energy utility companies, generation and power services companies, transmission and distribution companies, and oil and gas companies. Overall, Mercer concluded that Fortis's total remuneration levels are, on average, nine per cent below the median of the comparator group.[109]

131. For its non-union assessment of ATCO Electric, Mercer compared compensation data for a peer group including 41 companies that, in its view, compete with ATCO Electric for non-executive talent. This peer group included Western Canadian-based utility, pipeline/midstream, engineering, procurement and construction, as well as select exploration and production (E&P) companies. The E&P companies chosen were limited to those between 50 per cent and 200 per cent of the ATCO Group's 2021 revenue of approximately $4 billion to ensure the peer group was not skewed towards the E&P sector.[110] Overall, Mercer concluded that ATCO Electric's target total remuneration is eight per cent below the 50th percentile, which is the level to which ATCO Electric claimed it manages non-union labour costs.

132. The CCA opposed the applied-for salary increases of both ATCO Electric and Fortis on the basis that they are forecasting substantially higher increases for 2022 and 2023 than are reasonable. The CCA noted that:

- The Alberta average of all Alberta settlements[111] and of Alberta utilities, both of which are applicable to union employees, is less than the salary escalations proposed by Fortis and ATCO Electric.

- The peer groups used by Mercer are flawed in two ways:
  - (i) The peer groups include all Alberta distribution utilities. The CCA argued that the distribution utilities entering a COS year each forecast high settlements, which presumably are reflected in the budgets that Mercer surveyed. The CCA submitted that using the Mercer report would result in "boot-strapping" requested increases in compensation by using other utilities in similar proceedings to justify increases, thereby creating a circular chain of reasoning.
  - (ii) Oil and gas E&P companies are used in the peer groups.[112] The UCA agreed with the CCA that the inclusion of E&P companies was unjustified and added that E&P companies are fundamentally different than utility companies for many reasons, including that these companies are unregulated, face an entirely different

[109] Exhibit 26615-X0031, Fortis application, paragraphs 165-168.
[110] Exhibit 26615-X0023, ATCO Electric application, Appendix C.3, PDF page 96.
[111] "all Alberta settlements" refers to wage settlements in Alberta for all industries.
[112] Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraphs 164-165.

risk profile, and may compensate their employees with variable compensation that could vary with underlying commodity prices.[113]

- For the last nine years under PBR incentives, the utilities have determined that below median pay is reasonable. The CCA stated that if these pay scales were good enough for shareholders, they are good enough for customers.[114]

133. IPCAA and the UCA also found it problematic that Mercer included E&P companies for the purpose of the peer comparisons of Fortis and ATCO Electric.[115]

134. The Commission examines the proposed salary escalations of Fortis and ATCO Electric for non-union and union employees in the paragraphs that follow. The Commission has decided to assess Fortis's non-union and executive employees on a combined basis. Awarding a combined amount for these employee groups gives Fortis the flexibility to determine how it should allocate its approved base pay increases.

5.3.1 Non-union employees

135. The Commission finds the salary escalations proposed by Fortis and ATCO Electric for non-union employees to be reasonable and approves them as filed, for the reasons that follow.

136. ATCO Electric provided updated data from February 2022 that shows the Alberta AWE index is higher than originally forecast. In this context of inflationary pressures resulting in higher salary expectations, the Commission does not find it reasonable to deny the proposed wage escalation rates. Doing so could negatively affect the ability of ATCO Electric and Fortis to attract and retain employees.

137. The Commission has reviewed the non-union market positioning estimates put forth by Mercer. While the Commission is mindful of the limitations it has previously expressed with respect to Mercer's analyses,[116] the Commission also notes that the target total remuneration levels of ATCO Electric and Fortis are below median levels. Fortis's current target total remuneration level is 91 per cent of the median target, which, in Fortis's view, is considered competitive, but near the lower bound of competitiveness.[117] ATCO Electric is similarly situated, in terms of competitiveness, at eight per cent below the median.[118] With respect to the CCA's argument that employee wages were below median during the PBR term, and therefore should continue in the future, the most recent data used by Mercer, collected in February 2022, shows higher salary projections than those requested by Fortis.[119] Mercer stated that its most recent median salary increase budget projections are three per cent for Fortis's peer group, 2.6 per cent

113 Exhibit 26615-X0410, UCA-AUC-2022MAR14-005, PDF pages 10-11.
114 Exhibit 26615-X0481, Written version of the CCA's oral argument, paragraphs 60-61.
115 Exhibit 26615-X0364, IPCAA-AUC-2022MAR14-005, PDF pages 19 and 20; Exhibit 26615-X0410, UCA-AUC-2022MAR14-005, PDF pages 10-11.
116 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.
117 Exhibit 26615-X0042, Fortis application, Appendix J, PDF pages 4 and 6.
118 Exhibit 26615-X0023, ATCO Electric application, PDF page 21, paragraph 52.
119 Exhibit 26615-X0417, Appendix A, Mercer rebuttal evidence, PDF page 3.

for all utilities, and three per cent for all energy companies.[120] In this context, the Commission considers that the increases proposed by ATCO Electric and Fortis for non-union employees will allow them to continue to have competitive total remuneration which, in turn, will enable them to attract and retain employees. The Commission finds no reason to conclude that the recent Mercer data does not reflect the current economic situation in Alberta.

138. The Commission does not find that the CCA's evidence was helpful in determining the reasonableness of the 2023 non-union salary escalations for Fortis and ATCO Electric. 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 are in a different employment market than non-union employees. They also have different rights and obligations attached to their employment relationship. Accordingly, absent relevant evidence to the contrary, it is unreasonable to assume, much less conclude, that salary escalations that may be warranted for union employees are reasonably applicable to non-union employees.

139. Likewise, the Commission is satisfied that Mercer's inclusion of other distribution utilities in its peer group comparators for ATCO Electric and Fortis does not create a circular reasoning chain. If all regulated utilities were removed from Fortis's peer group, the median 2022 salary increase budget projections would remain at three per cent.[121]

140. Mercer included exploration and production companies in its peer group comparators for ATCO Electric and Fortis. IPCAA and the UCA correctly identified that exploration and production companies have a different risk profile, and their employees bear this risk. Fortis stated that approximately 25 per cent of its external hires in 2020 and 2021 had recent oil and gas experience.[122] The Commission is not persuaded of the merit of including exploration and production companies in the Mercer comparator groups generally, but finds there is insufficient evidence on this record to exclude them. In any event, while it has taken directional guidance from the Mercer evidence, the Commission has made its determinations on the ATCO Electric and Fortis non-union labour escalators in light of the current economic circumstances facing utilities in Alberta rather than relying exclusively on Mercer's comparator data and related recommendations.

5.3.2 Union employees

141. The Commission finds that ATCO Electric's proposed salary escalations for union employees are reasonable. No party in this proceeding took issue with ATCO Electric's forecast union escalations. These escalations are based on an agreement that the Canadian Energy Workers Association (CEWA) ratified with ATCO Electric's corporate parent CU Inc. It is reasonably expected that this agreement would form a basis for an agreement with ATCO Electric. The Commission finds that, for reasons similar to the reasons stated above for non-union employees, 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.

120 Exhibit 26615-X0417, Appendix A, Mercer rebuttal evidence, PDF page 2.
121 Exhibit 26615-X0417, Mercer rebuttal evidence, PDF page 3.
122 Exhibit 26615-X0416, Fortis rebuttal evidence, paragraph 52.

142. Unlike ATCO Electric, Fortis provided little information on the record of this proceeding that justified its proposed 2.5 per cent salary increase for union employees even though approximately 78 per cent of its FTE employees are expected to be unionized in 2023. Fortis's collective agreement with these employees expires on December 31, 2022.[123]

143. Fortis used the same escalation percentage for union employees as for its non-union employees; however, Mercer's and Willis Towers Watson's evidence only supported Fortis's non-union salary escalations. Fortis also indicated that its escalation rates were considered in view of CPI forecasts.

144. J. Thygesen's evidence, on behalf of the CCA, using a sample size of utility settlements consisting of two collective bargaining agreements in 2023, indicated that expected escalation for union employees is 1.78 per cent for all utility wage settlements. However, this was based on an assessment of collective bargaining agreements made prior to January 2022, which does not account for more recent changes in economic conditions.[124]

145. The Commission paired ATCO Electric and Fortis in the present proceeding to allow, among other things, for better comparability (to the extent possible) between the two utilities. In this proceeding, ATCO Electric, a distribution utility that is presumably similarly situated to Fortis in terms of managing the costs of labour expenses, applied for a 2.4 per cent increase for union employees. It is also the case that Mercer assessed that both utilities' compensation was similarly below the market median. Given that the agreement between CEWA and CU Inc. was ratified in 2021,[125] and recognizing current economic realities and the associated higher salary expectations as discussed above, the Commission finds that Fortis's forecast union salary increases of 2.5 per cent in 2023 is reasonable. The Commission also took into consideration the fact that Fortis's overall labour escalation forecast of 2.5 per cent for union and non-union employees is less than ATCO Electric's labour escalation forecast of 2.75 per cent (as shown in Table 9 above). As a result, Fortis's applied-for 2.5 per cent escalation for union employees is approved.

5.4 Placeholders

146. ATCO Electric and Fortis included several placeholders in their applications. These are amounts that will be trued up when actual data becomes available. In this section, the Commission addresses these requests.

5.4.1 2021 and 2022 actual rate base

147. Both ATCO Electric and Fortis have included placeholders for their respective opening 2023 rate base consistent with Decision 26354-D01-2021,[126] because the 2021 and 2022 actual capital inputs and 2022 actual closing rate base were not available at the time of application

---

[123] Exhibit 26615-X0031, Fortis application, paragraphs 94-95.
[124] Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraph 159.
[125] Exhibit 26615-X0023, ATCO Electric application, PDF page 20, paragraph 50.
[126] Decision 26354-D01-2021, paragraph 25. The Commission accepted the utilities' request for placeholder treatment for the opening 2023 rate base.

filing. Both utilities produced their 2021 and 2022 capital forecasts generally relying on the same methodology used to forecast the 2023 capital costs.

148. ATCO Electric and Fortis updated their respective 2021 capital costs with non-audited 2021 actual amounts on April 1, 2022. As set out in Section 8.1, 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 Electric and Fortis to incorporate the 2021 actual rate base into their compliance filings.

149. 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.[127] Any changes or adjustments to the 2023 revenue requirements as a result of the finalization of the 2023 opening rate base will subsequently be trued up as part of an annual PBR rate adjustment filing.

5.4.2 ROE and equity thickness

150. ATCO Electric and Fortis included in their respective applications an equity thickness of 37 per cent and ROE of 8.5 per cent as placeholders pending a final determination of these parameters. In accordance with the findings in Decision 27084-D01-202,[128] an equity thickness of 37 per cent and ROE of 8.5 per cent are the final approved parameters for each utility in 2023.

5.4.3 Cost of debt

151. In its application, ATCO Electric forecast an interest rate of 4.13 per cent for debentures in 2023 and its corresponding 2023 embedded cost of debt is 4.34 per cent.[129] Fortis forecast an interest rate of approximately 4.23 per cent for debentures in 2023 and its corresponding 2023 embedded cost of debt is 4.43 per cent.[130] On December 15, 2021, the Commission issued a letter setting out the issues list for this proceeding and cost of debt was among the issues that required no additional materials or review for both ATCO Electric and Fortis.[131]

152. On December 22, 2021 the CCA filed a letter that proposed to include the cost of debt in the issues list, arguing that the long-term debt rate proposed by ATCO Electric was over-forecast.[132] The Commission denied this request but directed ATCO Electric and Fortis to "discuss whether their 2023 forecast cost of debt needs to be updated when they file their 2021 actuals update on April 1, 2022."[133]

---

127 The Commission retains the ability to review 2022 actuals for prudence, as outlined in Section 7.1 of this decision.
128 Decision 27084-D01-2022: 2023 Generic Cost of Capital, Proceeding 27084, March 31, 2022, paragraph 55.
129 Exhibit 26615-X0023, ATCO Electric application, paragraphs 73 and 76.
130 Exhibit 26615-X0031, Fortis application, paragraph 254.
131 Exhibit 26615-X0084, AUC letter - Preliminary list of issues and directions on procedure, Appendix A and Appendix B.
132 Exhibit 26615-X0092, CCA Letter re Issues List, paragraphs 15-16.
133 Exhibit 26615-X0122, AUC letter - CCA requests for an expansion of the issues list and filed budget, paragraph 6.

153. Fortis submitted that the cost of debt for 2022 and 2023 should be updated in the compliance filing for this proceeding.[134] It noted that there have been further developments in the macroeconomic environment and market volatility in capital markets that will impact Fortis's 2022 and 2023 cost of debt. Fortis recommended the 2023 cost of debt be trued up to the actual cost of debt. It claimed that doing so will ensure that customers bear no more than Fortis's actual cost of debt and will eliminate the need to spend any additional time or resources in trying to forecast this expense.[135] Fortis added that evolving economic conditions and inflationary pressures since it prepared its 2023 COS application have resulted in widening credit spreads for both long-term and short-term debt. ATCO Electric did not comment on this issue as part of its 2021 actuals update submission.[136]

154. The Commission denies Fortis's request to update the cost of debt in the compliance filing of this proceeding. For ratemaking purposes, the 2023 weighted average cost of debt is used and it is largely determined by actual historical debt issuances. The incremental impact of forecast 2023 issuances is not material. The Commission finds that it is both reasonable and more efficient to use the applied-for forecast cost of debt for the purposes of this decision. Accordingly, the Commission is satisfied that the applied-for forecast cost of debt in 2023 is reasonable. Of note, the 2022 cost of debt will be trued up to reflect the actual cost as part of the 2023 opening rate base update discussed earlier in this section.

5.4.4 Fortis's depreciation placeholder

155. Fortis requested placeholder treatment for its 2023 depreciation expense pending the outcome of any future proceeding addressing depreciation studies. This request is consistent with the determinations at paragraph 48 of Decision 26354-D01-2021, and, therefore, the Commission approves it.

5.5 Demand-side management programs

156. Demand-side management (DSM) consists of actions, activities and programs that influence consumer behaviours to lower energy usage.[137] DSM includes energy efficiency measures that lower total energy consumption typically with no degradation in service quality. It also includes demand response technologies and measures that allow consumers (or a third party on behalf of a consumer) to manage the timing of energy consumption.

157. Both ATCO Electric and Fortis applied for approval to recover the costs of designing and implementing DSM programs. Fortis proposed to operate its projects on a pilot basis with expenditures forecast only to the end of 2023, whereas ATCO Electric's proposed program was designed, at least in part, to continue into the PBR3 term. While these are separate proposals, the Commission addresses them together in this section of the decision. For the reasons that follow, the Commission denies ATCO Electric's Emissions Reduction and Energy Efficiency Program (EREE) and Fortis's low-income DSM initiative, customer education and awareness of smart

---

134 Exhibit 26615-X0422, Preliminary (non-audited) 2021 Actuals, paragraph 36.
135 Exhibit 26615-X0422, Preliminary (non-audited) 2021 Actuals, paragraph 42.
136 Exhibit 26615-X0412, ATCO Electric 2021 Preliminary (unaudited) Actuals.
137 Exhibit 26615-X0051, Appendix G-2 AEG Research in Support of FortisAlberta DSM Program Application, PDF page 3.

services and technology initiatives, but approves Fortis's managed electric vehicle (EV) charging pilot.

158. ATCO Electric stated that its proposed DSM program, EREE, would "reduce total bill costs, enhance customer satisfaction, influence customer behaviour, complement grid modernization and non-wires alternative initiatives, delay or avoid costly infrastructure upgrades and decarbonize electric service offerings."[138] It proposed two subprograms under the EREE, with total forecast O&M expenditure of $885,000 in 2023.

159. The first subprogram is the customer energy literacy program. It would provide residential customers with home energy reports including data on monthly usage disaggregated by individual components (such as entertainment, heating, cooking), together with information on the relative efficiency of appliances, as well as personalized energy insights and energy-saving tips to help customers better understand usage. ATCO Electric forecast that the literacy subprogram would cost $485,000 in 2023.[139]

160. The second subprogram is a proposal to spend $400,000 to engage a consultant for an EREE program planning, design and implementation (PPDI) study.[140] ATCO Electric explained that the PPDI study would provide insights on potential programs for implementation, as well as program costs, decarbonization expectations and net customer savings. This information would assist ATCO Electric in planning EREE programs beyond 2023 and provide guidance to both itself and the Commission with respect to a financial framework under which an EREE program could be delivered based on best practices in other jurisdictions.[141]

161. In its application, Fortis requested approval for three DSM pilot projects totalling $2.4 million in capital additions in 2023.[142] Fortis stated its proposed DSM program would allow low-income, rural residential and farm customers to manage their consumption and costs by making their demand data available. Fortis indicated that pursuing its DSM programs on a pilot basis would allow it to take a measured approach in investigating solutions to customer issues.[143] Fortis proposed to capitalize the costs of these programs with deferral account treatment.

162. The three pilot projects proposed by Fortis are as follows:

(i) **Low-Income DSM Initiative:** A proposed pilot project to provide low-income families with deep home envelope energy efficiency measures (e.g., furnace upgrades, insulation replacements, etc.). Fortis forecast the costs for this pilot to be approximately $1.4 million.[144] The breakdown in costs is approximately 125 customers at an average cost of $10,000 per customer, with an additional $150,000 allotted for program design.[145]

[138] Exhibit 26615-X0023, ATCO Electric application, PDF page 40, paragraph 123.
[139] Exhibit 26615-X0023, ATCO Electric application, PDF page 40, paragraph 124.
[140] Exhibit 26615-X0023, ATCO Electric application, PDF page 40, paragraph 125.
[141] Exhibit 26615-X0023, ATCO Electric application, PDF page 40, paragraph 125.
[142] Exhibit 26615-X0039, Appendix G - Demand Side Management Program DSM, PDF page 32.
[143] Exhibit 26615-X0039, Appendix G - Demand Side Management Program DSM, PDF pages 9-10.
[144] Exhibit 26615-X0039, Appendix G - Demand Side Management Program DSM, PDF page 24.
[145] Exhibit 26615-X0416, Fortis rebuttal evidence, paragraph 20.

(ii) **Customer Education and Awareness of Smart Services and Technology Initiative:** This initiative would provide customers with resources on smart home/smart farm technologies and services that enable direct control and understanding of their consumption patterns and costs. There would be separate programs for residential and farm customers.[146] Fortis forecast the cost to be approximately $600,000, serving approximately 1,100 customers at a cost of $440,000, with the remaining $140,000 allotted for program design.[147]

(iii) **Managed Electric Vehicle Charging Pilot:** Fortis explained that it does not have visibility of the location of EV chargers at residential premises, unless a panel upgrade is required to accommodate additional load. Under this program, Fortis proposed to work with customers to understand where and when EV charging is drawing large amounts of power, allowing for a proactive approach to infrastructure investments. Fortis forecast the cost of this pilot to be approximately $350,000. It anticipated that this budget would allow Fortis to engage approximately 600 customers with a $200 sign-up incentive and monthly incentive payments of $5-$10 per month, with the remaining $140,000 budgeted being allotted for program design.[148]

163. Fortis argued that, in general, DSM programs lower the overall cost of electricity to end-users by optimizing system assets and encouraging customers to use energy more efficiently.[149] Fortis contended that its proposed DSM program would have numerous social benefits, including decreased emissions, addressing energy poverty and reducing costs for vulnerable populations.[150]

164. The UCA opposed the respective DSM programs of both ATCO Electric[151] and Fortis. The UCA sponsored the evidence of R. Bell, who considered that such programs were unrelated to the provision of safe and reliable service and therefore fall outside of the duties of a regulated utility.[152] R. Bell proposed that a coordinated province-wide strategy would be preferable to separate programs put forward by each individual utility, because a province-wide strategy would avoid duplication and provide consistent messaging.[153]

165. R. Bell also raised concerns that the DSM programs lacked detailed evidence to support the prudency of the proposed expenditures and to demonstrate tangible benefits to ratepayers.[154] He further submitted that updating rates to include a demand component could be a more

146 Exhibit 26615-X0039, Appendix G - Demand Side Management Program DSM, PDF pages 25-26.
147 Exhibit 26615-X0416, Fortis rebuttal evidence, paragraph 24.
148 Exhibit 26615-X0416, Fortis rebuttal evidence, paragraphs 22-23.
149 Exhibit 26615-X0416, Fortis rebuttal evidence, paragraph 25.
150 Exhibit 26615-X0039, Appendix G - Demand Side Management Program DSM, PDF pages 28-29.
151 Exhibit 26615-X0328, UCA evidence (redacted), PDF page 36.
152 Exhibit 26615-X0328, UCA evidence (redacted), PDF page 35.
153 Exhibit 26615-X0410, UCA-AUC-2022MAR14-006(a).
154 Exhibit 26615-X0410, UCA-AUC-2022MAR14-006(a) and 007.

effective mechanism for managing EV charging load than the rebate system proposed by Fortis in its Managed EV Charging pilot.[155]

166. The UCA also stated that when programs, such as DSM, are linked to specific utilities, they may become a branding exercise; that is, a means to keep the utility in the public eye.[156] The UCA explained that it supports efforts to ensure customer bills are as low as possible and recognizes value in customer education. It argued, however, that the current proposals are "haphazard, inefficient and potentially confusing to customers."[157]

167. For the reasons that follow, the Commission denies ATCO Electric's EREE Program and Fortis's Low-Income DSM Initiative, and Customer Education and Awareness of Smart Services and Technology Initiative.

168. While DSM programs may be beneficial to all customers, the Commission is not persuaded that it is reasonable to include these costs in Fortis's forecast revenue requirement. Fortis acknowledged that there is no "right way" to administer energy efficiency programs and that such programs can be run by utilities, government agencies or third parties, with distinct advantages and disadvantages to be considered in deciding which approach is most appropriate.[158] The Commission is not satisfied that Fortis fully considered the advantages and disadvantages of a DSM program run by entities other than a utility, to identify the best approach for its customers.

169. The UCA is the entity tasked by the provincial government to provide customer education on electric and natural gas utilities.[159] In this legislative and policy context, the Commission puts considerable weight on the UCA's submissions that customer confusion may result from unique and independent DSM programs being undertaken by individual distribution utilities.

170. The Commission agrees with the UCA that there is the potential for cost duplication and that it may be more efficient to take a more coordinated approach to DSM programming. While ATCO Electric's EERE program and Fortis's Customer Education and Awareness of Smart Services and Technology Initiative would serve different customers, there could be clear synergies in the development of coordinated planning and implementation, given that the target customers and desired outcomes are similar. ATCO Electric and Fortis indicated that in preparing proposals for their respective DSM programs, they coordinated with other electric distribution entities (referred to collectively as the Alberta Smart Grid Consortium) to hire a third party to conduct market research.[160] The Commission sees no reason why these utilities could not

[155] Exhibit 26615-X0410, UCA-AUC-2022MAR14-006(d), PDF page 17.
[156] Exhibit 26615-X0328, UCA evidence (redacted), PDF page 35.
[157] Exhibit 26615-X0476, UCA oral argument (written version), paragraph 25.
[158] Exhibit 26615-X0052, Appendix G-3 Dunsky Energy Consulting - Integrating Energy Efficiency into the Utility System, PDF page 16.
[159] *Government Organization Act*, Schedule 13.1, Section 3.
[160] Exhibit 26615-X0039, Appendix G - Demand Side Management Program DSM, PDF page 10. The Alberta Smart Grid Consortium consists of Alberta Innovates (a Provincial Crown Corporation), Alberta Energy and the Alberta distribution facility owners, including ATCO, ENMAX, EPCOR, Fortis, Alberta Federation of Rural

continue to work collaboratively among themselves and with the UCA to deliver coordinated DSM programming, particularly because the utilities have indicated that DSM programs are in the public interest and that they serve similar customer demographics.

171. Accordingly, ATCO Electric's EERE program and Fortis's Low-Income DSM Initiative and Customer Education and Awareness of Smart Services and Technology Initiative are denied. The Commission directs ATCO Electric and Fortis to remove their respective expenditures associated with these programs and initiatives from their 2023 forecasts in their compliance filings.

172. For the reasons set out below, the Commission approves Fortis's Managed EV Charging pilot.

173. On December 6, 2018, the Commission initiated the Distribution System Inquiry (DSI) with the express purpose of identifying key issues related to the future of the electric distribution grid, to aid in developing the necessary regulatory framework to accommodate the evolution of the electric system.[161] The resulting DSI report[162] set out key findings, one of which identified changes that will challenge the distribution utilities. For example, utilities will need to deal with dynamic energy flows on their systems, changing customer expectations and the implementation of new technologies to help respond to an industry in transition.[163]

174. Following the DSI, in Decision 23943-D01-2020, the Commission recommended that the Alberta Electric System Operator (AESO) and distribution utilities consider operational measures, such as non-wires alternatives, to alleviate pressures for continued growth in utility capital spending.[164] The Commission finds that Fortis's proposed Managed EV Charging Pilot will provide the kind of information that was contemplated in the DSI and that Fortis will need to build, upgrade and improve its electric distribution system. Further, this pilot program responds to the Commission's suggestion to consider non-wires alternatives to lower system costs. The Commission approves the forecast 2023 additions for this program on a pilot basis only. Accordingly, the Commission directs Fortis to define key performance indicators for this pilot, to file these metrics in its compliance filing and to report the results to the Commission within six months of the completion of the pilot. The results of the pilot will be considered by the Commission when reviewing any future EV charging applications made by Fortis.

175. The Commission is also mindful of R. Bell's submission that rates could be preferable to rebates in incenting changes to customers' EV charging behaviours.[165] This submission

---

Electrification Associations, EQUS REA LTD. and the Cities of Lethbridge, Medicine Hat and Red Deer. "The Consortium works collaboratively to understand the impacts and opportunities of grid modernization solutions by enabling the development, deployment and use to meet the current and evolving needs of their electricity consumers." See the Distribution System Inquiry – Final Report, Proceeding 24116, footnote 468.

161 Bulletin 2018-17, Electric Distribution System Inquiry, December 6, 2018.

162 Proceeding 24116, Distribution System Inquiry - Final Report, February 19, 2021.

163 Proceeding 24116, Distribution System Inquiry - Final Report, Section 2.2 Key takeaways.

164 Decision 23943-D01-2020: Alberta Electric System Operator, EPCOR Distribution & Transmission Inc. – West Edmonton Transmission Upgrade Project, Proceeding 23943, Applications 23339-A001 to 23339-A006, March 12, 2020, PDF page 40, paragraph 155. This was also quoted in the Distribution System Inquiry – Final Report, Proceeding 24116, paragraph 414.

165 Exhibit 26615-X0410, UCA-AUC-2022MAR14-006(d), PDF page 17.

corresponds with the observations in the DSI report, which also identifies improving rate design as a mechanism for managing integration of distributed energy resources onto the grid.[166]

176. The Commission is interested in comparing the efficacy of incentive programs against alternative rate design (for example, time-of-use rates) as a mechanism for managing EV charging loads. If it is possible to do so within the forecast costs for this pilot project, the Commission encourages Fortis to include a proposal for an alternative rate pilot on a subset of customers within its managed EV charging pilot in its compliance filing.

177. As directed in Section 5.2, Fortis must adjust its forecast for this program to reflect the approved escalation factors.

178. Fortis also requested a deferral account for its Managed EV Charging Pilot but did not file substantive evidence in support of the request. As a result, the Commission is unclear why a deferral account is required, given that recovery of capital costs occurs over a period of years, based on the depreciation rates of the assets involved. The project does not appear to align with the criteria typically considered by the Commission when evaluating the need for deferral accounts.[167] Specifically, the forecast amount of $350,000 is not material to Fortis's overall application, and given that the project is proposed and planned by Fortis, the Commission considers the project forecast and actual costs to be within Fortis's control. Consequently, the Commission denies the use of a deferral account.

6 Removal of REA-related costs from Fortis's revenue requirement

179. Fortis's service area overlaps with the service areas of certain rural electrification associations (REAs), and Fortis incurs certain costs as a result of integrated operations with these REAs. In Decision 25916-D01-2021, the Commission found that it did not have authority to approve the type of costs referred to as "Fortis's costs to serve REAs under integrated operations" as part of Fortis's distribution tariff.[168] Rather, the legislative scheme required that public distribution utilities like Fortis enter into an "integrated operations agreement (IOA)," respecting the integrated operation of their electric distribution systems in a single geographic region.[169]

180. In Decision 26757-D01-2021,[170] the Commission determined that the total 2017 amount of costs to serve REAs that needed to be removed from Fortis's revenue requirement was $8.66 million, before conversion to 2023 dollars. The Commission directed Fortis to remove the estimated costs to serve REAs under integrated operations for 2023 from its revenue

[166] Distribution System Inquiry – Final Report, Proceeding 24116, Section 5.2.1.3.
[167] Decision 2012-237, paragraph 629.
[168] Decision 25916-D01-2021: FortisAlberta Inc., 2022 Phase II Distribution Tariff Application, Proceeding 25916, July 8, 2021, paragraphs 196 and 206.
[169] Decision 25916-D01-2021, paragraph 200, citing Proceeding 25201, Exhibit 25201-X0060, AUC letter – Ruling on jurisdiction to approve applied-for allocated distribution costs for FortisAlberta Inc., April 17, 2020, paragraphs 34, 36-38.
[170] Decision 26757-D01-2021: FortisAlberta Inc., Application for Review and Variance of Decision 25916-D01-2021, Proceeding 26757, December 9, 2021,

requirement. In updating Fortis's integrated operations costs for 2023, the Commission stated that "Fortis should, where possible, use the same methodology that has been approved in [Decision 25916-D01-2021]. However, if using the same methodology to arrive at the 2023 amount would require substantial effort (i.e., gathering new data and fully rerunning Fortis's component analysis method (CAM) model), then Fortis may propose a reasonable alternative."[171]

181. Fortis explained that re-running the CAM model to fully determine the actual cost is a Phase 2 exercise and is too onerous to undertake for this application.[172] Their proposed alternative was to use non-adjusted 2017 dollars (neither escalated, nor de-escalated to convert to 2023 dollars). The Commission does not consider such an approach to be reasonable, and finds that it does not comply with its earlier direction.

182. The following alternatives for determining 2023 amounts were canvassed in this proceeding: (i) escalating the 2017 cost by I-X; or (ii) escalating the 2017 costs by the same or similar escalation factor that Fortis proposed in the present rebasing proceeding. Fortis dismissed the approach of updating the amounts by applying I-X, stating that such an escalation approach would not be aligned with the overall approach to determining its 2023 distribution revenue requirement, generally.[173]

183. Regarding the second alternative, Fortis stated that Decision 25916-D01-2021 determined that these costs were unrecoverable from its customers and consequently, "there is no principled basis upon which to escalate these costs."[174] Fortis went on to state that these costs cannot be mechanistically escalated in a similar manner to other costs in its application to arrive at 2023 dollars because "a meaningful allocation of the net REA costs cannot be achieved by simply applying an escalation of costs *per se* but is also dependent on a correct assessment of whether and how FortisAlberta's and REAs' use of the distribution system may have changed."[175]

184. Fortis subsequently suggested that any adjustments to the 2017 amount could be determined in their next Phase 2 application.[176] However, Fortis also proposed that "it would be improper to apply any further adjustments attributable to the REA-related disallowance mid-way through the next PBR term, as this would amount to a retroactive adjustment to the revenue requirement that will be established at the end of the current proceeding."[177]

185. The Commission does not agree with Fortis's proposals either to use non-adjusted 2017 dollars, or to delay any updates until its next Phase 2. Fortis's proposal would put Fortis's customers at a disadvantage. In the Commission's view, it is inconsistent for Fortis to escalate costs that result in increases to its revenue requirement, while at the same time claiming that there is no principled basis to escalate costs that are to be removed from Fortis's revenue requirement. Moreover, Fortis has previously argued in two different proceedings that a Phase 2

171 Decision 25916-D01-2021, paragraph 230.
172 Exhibit 26615-X0031, Fortis application, paragraphs 531-532.
173 Exhibit 26615-X0031, Fortis application, paragraph 533.
174 Exhibit 26615-X0201, FAI-AUC-2022JAN14-040(c).
175 Exhibit 26615-X0201, FAI-AUC-2022JAN14-040(c).
176 Exhibit 26615-X0201, FAI-AUC-2022JAN14-040(c).
177 Exhibit 26615-X0201, FAI-AUC-2022JAN14-040(d).

proceeding is not an appropriate forum to address Phase 1 matters, such as the amount that should be removed from its revenue requirement connected with integrated operations.[178]

186. The Commission therefore directs Fortis to apply the same escalation factors approved in Section 5.2 of this decision to Fortis's 2017 costs to serve REAs under integrated operations (i.e., $8.66 million, per Decision 26757-D01-2021) to escalate those costs to 2023 dollars, and then to remove this amount from its revenue requirement in its compliance filing.

7 2023 forecast O&M

187. In Decision 26354-D01-2021, the Commission directed each of the utilities to provide historical cost comparisons and related variance explanations to support their 2023 O&M cost forecast.[179] The Commission also prepared a schedule[180] for the filing by electric utilities of O&M expenses, based on prior Rule 005 filings, which presents information at a uniform system of accounts level.

188. The DFOs were directed to apply materiality thresholds from Bulletin 2020-25[181] 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.

7.1 Fortis 2023 forecast O&M

189. Fortis forecast O&M expenses of $230.8 million for 2023 using a detailed estimate of labour, contractor, and other general operating costs.[182] Fortis stated that its labour forecast included the number of FTEs required by Fortis in 2023, and the rate of pay for each position for the forecast period. Additionally, the forecast for contractor and general operating expenses was developed based on the anticipated needs for 2023.[183]

190. To compare its forecast to historical actual spending, Fortis first escalated its comparative O&M amounts into 2023 dollars using its chosen inflation and customer additions growth escalators, as described in Section 5.2. Fortis stated that this approach eliminated the repetitive need to explain cost increases associated with CPI, salary adjustments undertaken in the PBR incentivized environment, or customer additions growth.[184] Fortis further confirmed that the customer additions growth escalator was not used in the development of its 2023 O&M forecasts, and that this escalator was only utilized to provide variance explanations on an "apples-to-apples" basis by normalizing inflation and customer counts.[185]

[178] Decision 26757-D01-2021, paragraph 15.
[179] Decision 26354-D01-2021, paragraph 21.
[180] Proceeding 26354, Post-disposition documentation, Appendix 2 - Final rebasing template - Electric, September 22, 2021.
[181] Bulletin 2020-25, Reducing Regulatory burden with materiality thresholds for review of cost of service rate applications, July 3, 2020.
[182] Exhibit 26615-X0031, Fortis application, paragraph 147.
[183] Exhibit 26615-X0031, Fortis application, paragraphs 148 and149.
[184] Exhibit 26615-X0031, Fortis application, paragraphs 137 and 138.
[185] Exhibit 26615-X0478, Fortis written version of oral argument, paragraph 29.

191. In the application, Fortis stated that the increase over historical O&M levels is mainly due to an increase in franchise fees under Taxes Other than Income Taxes as a result of the addition of franchise agreements, which is fully offset in revenue.[186] In other words, franchise fees are billed to, and collected from, the retailers by Fortis, and then paid to each municipality each month, resulting in a net zero impact to revenue requirement. Fortis also provided variance explanations for a number of expense accounts.[187] Further information on Overhead Line Maintenance, Customer Installations, and IT support was provided in response to Commission IRs.[188]

192. Interveners took issue with Fortis's forecast O&M costs. However, their objections and recommendations for a lower O&M forecast were primarily based on their general recommendation to use the lowest O&M cost year rebasing approach. For example, D. Madsen for IPCAA pointed out that FTE levels hit a low point in 2020, but the forecasts in 2023 represented the highest staffing levels for Fortis over the 2013-2023 period.[189] D. Madsen proposed that Fortis be directed to use 2020 actual costs, and escalate those costs using only an average of the previously approved I-X index, resulting in O&M costs (excluding distribution to transmission contributions and franchise fees) of $151.4 million, as opposed to the applied-for costs of $161.2 million.[190] The UCA took the view that the use of the lowest O&M cost year best reflects the incentives of PBR and would ensure PBR benefits are passed on to customers.[191]

193. As set out in Section 2 of this decision, the Commission permitted the utilities to utilize the hybrid approach to forecasting their 2023 costs, which allows the use of mechanistic and non-mechanistic methods. In this regard, the Commission finds that Fortis's use of a non-mechanistic approach to arrive at its 2023 O&M cost forecast is reasonable.

194. The Commission has reviewed the breakdown of FTEs and forecast salaries required for 2023, along with Fortis's explanations of cost drivers. The Commission views the FTE forecast to be reasonable. While the 2023 forecast for O&M is based on a bottom-up approach, it compares well with Fortis's escalated 2018-2020 average O&M expenditures. Without Fortis's expected increase in franchise fees (which are fully offset in revenue as explained above), Fortis's 2023 O&M cost forecast would be lower than the escalated 2018-2020 average by approximately $6.6 million.[192] Furthermore, Fortis demonstrated that even when the customer growth index is removed from the escalated 2018-2020 average, the applied-for forecast O&M expense (excluding taxes other than income taxes) is nearly identical to the revised escalated average.[193] As a result, the Commission finds Fortis's 2023 forecast O&M of $230.8 million to be reasonable.

186 Exhibit 26615-X0031, Fortis application, paragraph 242.
187 Exhibit 26615-X0031, Fortis application, PDF pages 65-85.
188 Exhibit 26615-X0201, FAI-AUC-2022JAN14-010, PDF pages 41-45; Exhibit 26615-X0201, FAI-AUC-2022JAN14-011, PDF page 46.
189 Exhibit 26615-X0298, IPCAA evidence of D. Madsen, page 41.
190 Exhibit 26615-X0298, IPCAA evidence of D. Madsen, pages 8 and 44.
191 Exhibit 26615-X0328, UCA evidence (redacted), PDF page 14.
192 Calculated as $6.5 million variance shown in Exhibit 26615-X0033, Appendix A – 2023 COS Rebasing Template, WP 2 tab, minus $13.1 million variance due to Taxes Other than Income Taxes.
193 Exhibit 26615-X0444, FAI-AUC-2022APR12-001, PDF page 4.

195. Fortis did not include any AESO customer contributions for 2023 in its O&M costs. Fortis also confirmed that it has not included any capital additions related to AESO customer contributions in its 2023 capital additions forecast.[194] Fortis indicated that in accordance with Decision 26521-D01-2021 it will treat any future AESO customer contributions as a Y factor. The Commission finds that Fortis's proposal complies with the directions related to the treatment of AESO customer contributions in Decision 26521-D01-2021.

7.2 ATCO Electric 2023 forecast O&M

196. For its 2023 O&M forecast, ATCO Electric used a hybrid approach. The majority of its O&M accounts were forecast mechanistically using the escalated 2018-2020 average of actual costs. As discussed below, a smaller subset of its O&M accounts were forecast using a bottom-up approach. ATCO Electric explained that, as seen in the table below, its total O&M costs, excluding Distribution to Transmission contributions of $30.6 million are lower than the PBR escalated 2013-2020 average and slightly higher than the escalated 2018-2020 average.

Table 11. ATCO Electric comparison of 2023 O&M to escalated O&M during PBR[195]

	2023 COS Forecast	PBR Escalated Average (2018-2020)	PBR Escalated Average (2013-2020)
Total Utility O&M costs included in base rates	$158,943	$152,616	$171,190

197. Interveners raised the same issues and objections with respect to ATCO Electric's forecast O&M costs as they did with respect to Fortis's forecast O&M costs; specifically, they submitted that both utilities' forecast O&M costs were too high and recommended that the Commission adopt the lowest O&M cost year approach to rebasing costs and revenues. As 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 Electric'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.

7.2.1 Mechanistic O&M

198. ATCO Electric forecast the majority of its 2023 O&M and administration and general (A&G) costs under the mechanistic approach.[196] ATCO Electric 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 Electric did not expect these costs to fluctuate materially from the amounts incurred over the 2018-2020 period.

199. The Commission approves the use of the mechanistic approach by ATCO Electric 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

[194] Exhibit 26615-X0201, FAI-AUC-2022JAN14-013(a), PDF pages 49-50.
[195] Exhibit 26615-X0023, ATCO Electric application, PDF page 12, Table 2. Exhibit 26615-X0024, Appendix A, ATCO Electric Commission Template, Schedule 3a.
[196] The costs that were mechanically forecast are set out in Exhibit 26615-X0024, Appendix A, ATCO Electric Commission Template, Schedule 3.

category did not require further detail or support because the forecast costs were aligned with a utility's past 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 these forecasts to be less susceptible to volatility in 2023 and beyond, given their predictable pattern in the past.

200. For these reasons, the Commission finds that ATCO Electric's O&M and A&G forecasts derived using the mechanistic approach, and adjusted by using the escalation factors approved in Section 5.2, are reasonable. The Commission directs ATCO Electric 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.

201. The remaining O&M and A&G forecasts that have been forecast using a non-mechanistic approach are addressed separately in the sections that follow.

7.2.2 Non-mechanistic O&M

202. ATCO Electric did not use a mechanistic methodology to develop its forecasts for the following accounts because it said that doing so would underfund expected spending required in 2023:

- Overhead Line Expenses (USA 583);
- Vegetation Management (USA 593.1);
- Administrative and General Salaries (Limited to Incremental Costs) (USA 920);
- Distribution to Transmission Contributions;
- Information Technology Costs (USA 599, 905.1, 934, 944.1); and
- EREE program (addressed in Section 5.5).

203. The EREE program is addressed in Section 5.5. As set out in the Commission's letter dated April 8, 2022, IT Costs will be addressed in the decision in Proceeding 26616 for both ATCO Electric and ATCO Gas North. A discussion of each of the remaining accounts follows.

204. The Commission approves the use of the non-mechanistic approach by ATCO Electric to develop the forecasts for those O&M and A&G expenses that were expected to materially differ from historical average expenditures incurred in PBR2. The cost items in this category were generally adequately supported with detailed business cases that consisted of project drivers and benefits, project costs broken down into various subcategories, and the evaluation of viable alternatives considered. The Commission found this additional information to be helpful and necessary, thus allowing it to conduct a thorough review of the costs in this category as presented in the remainder of this section.

7.2.2.1 Overhead line expenses

205. ATCO Electric forecast $18.4 million in the Overhead Line Expenses O&M account (USA 583) for 2023. This is an increase of $2.6 million from ATCO Electric's escalated 2018-2020 average of $15.8 million, produced by ATCO Electric's mechanistic approach. For the following reasons, the Commission approves a 2023 forecast of $17.1 million for this program.

206. The Commission is persuaded by the CCA's argument that the reduction in expenditures in the overhead line expenses were achieved by reducing service quality based on the decline in ATCO Electric's internal metrics. The CCA argued in this regard that the benefits of the alleged reductions were to the account of ATCO Electric's shareholders and that customers are now being required to pay to restore the service levels in 2023.[197]

207. ATCO Electric restructured this program during PBR. The restructuring involved a reduction of 71 distribution operations employees through permanent workforce reductions and attrition. This resulted in costs for the program decreasing from $30 million (using the escalated 2013 to 2017 average) to $15.8 million (using the escalated 2018-2020 average). After the restructuring of its workforce, ATCO Electric identified, through the monitoring of key internal metrics, a drop in internal standards which it said now requires additional costs to deliver sustainable reliability and customer service for overhead line operations.[198]

208. Although ATCO Electric continues to comply with the performance metrics set out in Rule 002,[199] it said the drop in its internal metrics, which it uses as leading indicators, show that future compliance with Rule 002 may be jeopardized if incremental expenditures are not made.[200]

209. The Commission accepts that initiatives undertaken in PBR to reduce costs can have unintended consequences and some trial and error may be required to "right-size" workforce requirements as described by ATCO Electric. However, the Commission also recognizes that ATCO Electric receives a financial benefit from any cost reductions achieved during the PBR term. ATCO Electric's shareholders received the benefit of the reduction in expenditures due to the cost cutting initiatives in the overhead line expenses O&M account, while still complying with the performance metrics set out in Rule 002.

210. It is not reasonable that customers should now be required to pay to restore service levels which ATCO Electric indicates were unsustainably eroded during the PBR term and for which customers derived no financial benefit until this rebasing, particularly where ATCO Electric continues to comply with legally imposed service standards. The Commission does accept however, that some level of incremental spending is required in this program to reverse the erosion of internal metrics observed by ATCO Electric. For these reasons, the Commission denies 50 per cent of the proposed $2.6 million increase over ATCO Electric's escalated 2018-2020 average amount of $15.8 million, for a total approved amount of $17.1 million for this

[197] Exhibit 26615-X0306, CCA evidence of J. Thygesen, PDF pages 58-60.
[198] Exhibit 26615-X0023, ATCO Electric application, Appendix H.1, PDF pages 156-159.
[199] Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors.*
[200] Exhibit 26615-X0177, AE-AUC-2022JAN14-003(a), PDF page 20.

program. The Commission directs ATCO Electric to reflect this approved forecast for this program in its compliance filing.

7.2.2.2 Vegetation Management

211. The vegetation management O&M account USA 593.1 collects the costs associated with managing vegetation in ATCO Electric's distribution system rights-of-way. During the first PBR term, ATCO Electric undertook an initiative to test different vegetation management techniques: herbicide conversion within the western portion of the service territory and a risk-based mechanical treatment (i.e., mowing, slashing and trimming) within the eastern portion of the service territory. Other O&M components of the vegetation management program include right-of-way patrols and inspections, addressing unplanned events and program management.

212. For 2023, ATCO Electric forecast that $18.3 million is required to execute a program that will see conversion to herbicide as the core management program across its entire service territory based on the results of the testing in the western portion of its service territory, which are explained below. This forecast is an increase of $6.8 million over the 2018-2020 escalated average of $11.6 million produced by ATCO Electric's mechanistic approach.[201]

213. In its application, ATCO Electric explained that it has determined the greatest efficiencies can be gained within the overall program by converting, to the extent possible, to the more cost-effective herbicide treatment. This treatment has the added benefit of reducing the unanticipated trimming on sites along power lines. Due to the need for two herbicide treatments in a relatively short period of time, ATCO Electric explained that there is an increase in costs in the short term but there are long-term financial benefits for customers. ATCO Electric also stated that the herbicide control has other benefits, including increased safety and system reliability and a reduced environmental impact compared to mechanical treatments.[202]

214. ATCO Electric tested a risk-based vegetation management approach in the eastern region during the PBR term. This involved just-in-time mechanical treatments, which it said can extend treatment cycles to when they are needed versus time regimented cycles. Cost savings were realized in the latter stages of the first and early in the second PBR term as treatment cycles were extended; however ATCO Electric found that over time these savings were unsustainable due to increasing unanticipated trimming on sites along power lines. For example, the number of required trimming activities increased from 803 in 2016 to 1,607 in 2020.

215. In a herbicide conversion test performed in the western region, ATCO Electric validated that herbicide conversion across the entire service area is the most cost effective approach. In particular ATCO Electric indicated that in light of the results of the test, it anticipates a 40 per cent reduction in vegetation management costs over 20 or more years if it implements a program that consists of 60 per cent herbicide and 40 per cent mechanical treatment.[203]

216. ATCO Electric also explained that it began the conversion process of the eastern region by implementing mechanical programs between 2019 and 2022 to prepare for the herbicide

201 Exhibit 26615-X0023, ATCO Electric application, Appendix H.2, PDF page 169.
202 Exhibit 26615-X0023, ATCO Electric application, Appendix H.2, PDF pages 170-171.
203 Exhibit 26615-X0023, ATCO Electric application, Appendix H.2, PDF pages 180-181.

treatment. As a result, ATCO Electric claimed that a failure to fund the vegetation management program at the levels required in 2023 as it proposed, will increase costs and delay conversion until a second mechanical treatment is conducted.

217. In response to a Commission IR regarding any environmental or regulatory concerns with respect to the use of herbicide treatments, ATCO Electric explained that there is a series of regulatory approvals and restrictions that limit the types and amounts of herbicides applied. It also clarified that all herbicides approved in Canada undergo rigorous testing and approvals through Health Canada as well as other regulations through the Alberta Government.[204]

218. The Commission has reviewed ATCO Electric's business case with respect to the vegetation management O&M program and, based on the information provided, is satisfied that the herbicide conversion of ATCO Electric's entire service area is reasonable based on the testing done in its western service territory during both PBR terms. The Commission finds ATCO Electric's evidence on the benefits of herbicide conversion to be persuasive and to permit a reasonable expectation of longer term cost benefits to consumers as well as enhanced safety and system reliability. ATCO Electric must follow all applicable regulations with respect to the type of herbicides used and how they are applied. Based on the above, the Commission approves ATCO Electric's 2023 forecast of $18.3 million for the vegetation management O&M account. The Commission also directs ATCO Electric to record the costs of the vegetation management O&M account over time and to be prepared to report on efficiencies realized in future proceedings.

7.2.2.3 Administrative and General Salaries

219. ATCO Electric used the escalated 2018-2020 average to develop its base forecast of $17.68 million for its Administrative and General Salaries account (USA 920) and then increased that forecast by $0.9 million related to the innovation function, which is discussed below. No intervener objected to the forecast costs for ATCO Electric's administrative and general salaries.

220. Innovation was designated a new central shared services function in 2020 and was first approved for both ATCO Electric Transmission and ATCO Pipelines the following year in Decision 24964-D01-2021.[205] The Commission determined in that decision that it considers innovation (and expenditures undertaken in pursuit thereof) to be a legitimate activity for regulated utilities.[206]

221. The Commission is satisfied that the $0.9 million in incremental costs above the escalated 2018-2020 average related to the innovation function is reasonable as it is in line with the Commission's prior approval of the group and allocation methodology in Decision 24964-D01-2021, as described above. As a result, the Commission approves the 2023 forecast for the administrative and general salaries USA Account 920 of $17.68 million.

[204] Exhibit 26615-X0177, AE-AUC-2022JAN14-004(b), PDF pages 25-26.
[205] Decision 24964-D01-2021: ATCO Electric Ltd., 2020-2022 Transmission General Tariff Application, Proceeding 29464, March 1, 2021.
[206] Decision 24964-D01-2021, paragraph 46.

7.2.2.4 Distribution to transmission contributions

222. In Decision 26521-D01-2021,[207] the Commission changed the accounting treatment for AESO customer contributions made after April 23, 2021. These contributions are now expensed in the year that they occur. ATCO Electric included $30.6 million in its 2023 forecast O&M expense for AESO customer contributions.[208]

223. ATCO Electric explained that its 2023 AESO customer contribution forecast is based on the Grande Prairie point-of-delivery Project. This forecast was tested and approved as part of ATCO Electric Transmission's 2020-2022 general tariff application in Decision 24964-D02-2021.[209] ATCO Electric also noted that including this $30.6 million, which represents six per cent of its applied-for revenue requirement, may result in rate shock.

224. Based on the above, the Commission approves $30.6 million in AESO customer contributions in ATCO Electric's 2023 O&M forecast. In reaching this decision, the Commission rejects ATCO Electric's submissions[210] that an alternative approach of capitalizing the contributions should be considered for the treatment of contributions attributable to this project. The Commission was clear in Decision 26521-D01-2021 that any contribution payments received after April 23, 2021, must be expensed in the year in which they occur.

225. With respect to ATCO Electric's submission that the $30.6 million forecast for 2023 has the potential to cause rate shock, in Decision 26521-D01-2021 the Commission allowed the DFOs to propose deferral treatment for some or all of the AESO customer contribution amounts that contribute significantly to rate shock.[211] If such concerns arise in 2023, ATCO Electric is directed to consider this measure in its compliance filing to this decision.

226. In response to a Commission IR, ATCO Electric explained that it intends to true up its 2023 AESO customer contribution forecast amounts as a Y factor in future rate adjustment filings. This is consistent with the Commission direction in paragraph 21 of Decision 26521-D01-2021 where it approved the proposal to file an annual forecast for the AESO customer contribution Y factor amounts, which would then be subject to true-up in subsequent annual rate filings. Because the AESO customer contribution amounts will be recovered by way of a Y factor, the Commission directs ATCO Electric to exclude these amounts from its PBR3 going-in rates, which is similar to how other Y factor amounts are treated.

---

[207] Decision 26521-D01-2021: Revised Regulatory Treatment for Alberta Electric System Operator Customer Contributions, Proceeding 26521, October 6, 2021.

[208] Any AESO customer contributions that occurred prior to April 23, 2021, followed the legacy approach where the contributions are added to rate base and amortized over the life of the asset. As a result, there are some legacy contributions still included in rate base that will continue to amortize.

[209] Decision 24964-D02-2021: ATCO Electric Ltd., 2020-2022 Transmission General Tariff Application, Proceeding 24964, March 19, 2021.

[210] Exhibit 26615-X0023, ATCO Electric application, PDF page 41, paragraph 130.

[211] Decision 26521-D01-2021, paragraph 22.

8 2023 forecast capital additions

227. In Decision 26354-D01-2021,[212] 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.

228. 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.[213]

8.1 Prudence review

229. 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. With the exception of ATCO Electric's IT/CIS costs reviewed in Proceeding 26616, the Commission has assessed the capital costs incurred by each of ATCO Electric and Fortis in the years 2018 to 2020 and finds them to be prudently incurred unless specifically addressed in this decision.

230. The applications included 2021 forecast costs on a placeholder basis. Consistent with the Commission's direction, ATCO Electric and Fortis filed their non-audited 2021 actual costs on April 1, 2021.[214] [215] As also directed by the Commission,[216] 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. In this proceeding, the Commission undertook an assessment of the utilities' 2021 non-audited actual costs. Both the Commission and interveners tested the 2021 actuals in the oral hearing.

231. 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 and in the decision to be issued in Proceeding 26616 regarding ATCO Electric's IT/CIS costs. 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

---

212 Decision 26354-D01-2021, Section 4.2.
213 Decision 26354-D01-2021, Section 4.3.
214 Exhibit 26615-X0412, ATCO Electric 2023 COS application 2021 preliminary (unaudited) actuals, April 1, 2022; Exhibit 26615-X0413, Attachment 1 - ATCO Electric 2021 preliminary (unaudited) actuals vs forecast, April 1, 2022.
215 Exhibit 26615-X0422, 2022-04-01 Preliminary (non-audited) 2021 Actuals Submission; Exhibit 26615-X0423, Appendix A-2021 Capital Additions and O&M.
216 Exhibit 26615-X0411, AUC letter - Clarification on April 1 filing and ATCO Electric request to change process and schedule, paragraph 7.

reported in 2021 Rule 005 filings. The Commission directed the utilities to file these explanations as part of their compliance filings to this decision.[217]

232. Lastly, the Commission has reviewed the utilities' 2022 forecast costs and, with the exception of cost items specifically addressed in this decision (and the decision to be issued in Proceeding 26616 regarding ATCO Electric's IT/CIS costs), finds them to be reasonable and approves them on a placeholder basis. The mechanistically forecast 2022 programs are reflective of the 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.

233. 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.[218] 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 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 result in disallowances and potential changes to going-in rates if the Commission is not persuaded that the 2022 actual capital additions were prudent.[219]

8.2 Fortis 2023 forecast capital additions

234. As explained in Section 3, Fortis forecast its 2023 capital additions by combining mechanistic forecasts based on the escalated 2018-2020 average capital additions, and non-mechanistic forecasts, using a bottom-up forecasting methodology.[220] The majority of Fortis's forecasts were developed non-mechanistically, although in many cases Fortis embedded some form of mechanistic forecast (often escalated average unit costs) into its forecasting methodology.

235. Consistent with Decision 26354-D01-2021,[221] Fortis categorized its capital projects as either recurring or non-recurring. Recurring capital projects are predictable and expected to recur in the future. Non-recurring capital projects are either new, not part of Fortis's ongoing business operations, projects whose drivers have changed, or projects where costs are not forecast to

217 Transcript, Volume 6, pages 911-912.
218 Decision 26354-D01-2021, paragraph 45.
219 Decision 26354-D01-2021, paragraph 25.
220 Exhibit 26615-X0031, Fortis application, paragraph 20.
221 Decision 26354-D01-2021, paragraph 30 (ii)-(iv).

continue beyond 2023. Recurring projects make up approximately 94 per cent of Fortis's forecast gross capital expenditures for 2023.[222]

236. Fortis forecast its capital additions as shown in the table below.

Table 12. Fortis 2020-2023 forecast capital additions

Capital grouping	2020A	2021F	2022F	2023F	Forecast methodology
	($ million)				
Externally Driven System Modifications	60.8	60.8	60.0	65.3	Distribution Line Moves and High Load Corridor Clearances: Mechanistic Remainder of program: Non-mechanistic
Customer Growth	92.1	94.3	114.5	150.1	Non-mechanistic
Environment, Safety and Reliability	60.4	78.9	80.4	65.2	Aging Facilities: Mechanistic Remainder of program: Non-mechanistic
Forestry Protection	4.8	8.0	9.0	25.7	Previously Trimmed Tree Removal and Forest Protection Area Maintenance programs: Mechanistic Wildfire Mitigation: Non-mechanistic
Metering	10.8	15.0	9.0	19.9	Non-mechanistic
Rebuilds, Replacements and Life Extensions	47.6	52.5	48.5	59.3	Bulk Lamp Replacements: Mechanistic Remainder of program: Non-mechanistic
General Support	56.7	57.3	77.7	67.2	Non-mechanistic
System Purchases (REAs, Annexations)	0.0	0.0	13.0	15.0	Non-mechanistic
Distribution to Transmission Contributions	39.4	0.0	0.0	0.0	Non-mechanistic
Distribution Voltage Management*	0.0	0.0	0.0	7.8	Non-mechanistic
Secondary Upgrades**	0.0	0.0	0.0	5.3	Non-mechanistic
Remote Community Reliability	0.0	0.0	0.0	2.1	Non-mechanistic
Total	372.6	366.7	413.5	482.9	

Source: Exhibit 26615-X0033, Appendix A, 2023 COS Rebasing Template, Schedule 4.1, and Exhibit 26615-X0444, FAI-AUC-2022APR12-001, PDF pages 6-7.
*This capital program will be classified as recurring and become part of the Environment, Safety and Reliability program subsequent to 2023.
***This capital program will be classified as recurring and become part of the Externally Driven System Modifications Program subsequent to 2023.

237. The Commission approves the following projects, subject to Fortis applying the escalation factors approved in Section 5.2 of this decision. This includes the direction to remove the customer growth escalator from the calculation of its unit prices for all of Fortis's capital

[222] Exhibit 26615-X0031, Fortis application, paragraph 98.

additions where the forecast was obtained by multiplying the unit prices (calculated using the escalated 2018-2020 average) by the number of units (estimated from the bottom up).

238. To ensure completeness and accuracy, Fortis is directed to update its summary table in IR response FAI-AUC-2022APR12-001[223] by reviewing each capital category and program and clearly identifying what forecasting methods it used. If necessary, additional rows may be added to the table to specify the forecasting method for each capital project within a program. The Commission will also use this table (along with supporting calculations as discussed in the previous paragraph) to ensure that the escalators approved in Section 5.2 of this decision have been applied in accordance with the Commission's findings.

239. The Commission approves the forecast costs in the following capital groupings, subject to application of the escalation factors approved in Section 5.2 of this decision. Where specific programs within a capital grouping are listed, it is only the capital forecasts for those specific programs that the Commission approves.

- Externally Driven System Modifications:
    - Distribution Line Moves
    - High Load Corridor Clearances
- Environment, Safety and Reliability:
    - Compliance, Safety and Reliability
    - Worst Performing Feeders
    - Aging Facilities
- Rebuilds, Replacements and Life Extensions
- Forestry Projection:
    - Previously Trimmed Tree Removal
    - Forecast Protection Area Maintenance

240. These programs represent a mix of mechanistically and non-mechanistically forecast projects. Fortis's incorporation of escalated averages in its bottom-up forecasting resulted in forecasts that were generally aligned with the escalated 2018-2020 average. 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 Fortis's past 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. In cases where Fortis's bottom-up forecast differed materially from the escalated 2018-2020 average, Fortis either provided evidence that the projects had historically uneven spending patterns that could not easily be averaged, or that external factors were driving the need to diverge from historical spending patterns.

241. The remaining capital groupings and programs are addressed in the following sections.

[223] Exhibit 26615-X0444, FAI-AUC-2022APR12-001, PDF pages 6-7, Table "Capital Category Program Forecast Method."

8.2.1 Customer Growth

242. The Customer Growth category includes capital additions to install distribution facilities to connect new customers to Fortis's distribution system. Fortis forecast capital additions of $150.1 million in 2023 for this category by multiplying the number of new service locations forecast in 2023 by an escalated average 2018-2020 unit cost. More specifically, Fortis forecast that the number of 2023 new service locations in each rate class would be equal to the 2018-2020 average new service locations in the same rate classes. The average unit cost was forecast by averaging the 2018, 2019 and 2020 actual unit costs and escalating that average cost to 2023 dollars.[224]

243. Fortis later noted that it had overstated its 2023 forecast for the Customer Growth category by $5.303 million. It said that this error was due to the application of the customer additions growth escalator to the 2018-2020 historical unit costs used to develop the forecast.[225] Fortis submitted that its full forecast of $150.1 million, including the $5.303 million overstatement, was still reasonable, as increased quotation activity pointed to increased customer demand.[226] However, for the reasons set out below, Fortis has failed to persuade the Commission that including the $5.303 million overstatement is reasonable.

244. Fortis did not provide the calculations underlying its forecast for the Customer Growth category. The Commission has therefore relied on Fortis's statement that the error was due to Fortis applying both the inflation and customer growth escalators to the historical 2018-2020 unit prices in determining its unit price forecast for this program. As discussed in Section 5.2 the Commission finds that it is not appropriate to apply a customer growth escalator to unit price values. The customer growth escalator relates to the volume of work Fortis expects to complete, not the cost of that work. The Commission directs Fortis, in its compliance filing, to remove the application of the customer growth escalator from the determination of unit prices for the Customer Growth category.

245. Fortis's unit costs for Customer Growth are based on current maximum investment level rates. The Commission recognizes that Fortis's forecast may need to be revised if any changes are made to Fortis's maximum investment levels pursuant to the Commission's process established in Bulletin 2022-07.[227] As a result of that process, the Commission may issue further direction to Fortis on how to incorporate any changes to maximum investment levels at a later time.[228]

8.2.2 Environment, Safety and Reliability

246. Fortis is forecasting 2023 capital additions of $65.2 million in its Environment, Safety and Reliability capital grouping. It calculated this forecast based on escalated 2018-2020 average capital additions, with the exception of a small subset related to Supervisory, Control and Data

---

224 Exhibit 26615-X0031, Fortis application, paragraph 301.
225 Exhibit 26615-X0444, FAI-AUC-2022APR12-001, PDF page 8.
226 Exhibit 26615-X0444, FAI-AUC-2022APR12-001, PDF pages 8-9.
227 Bulletin 2022-07, Stakeholder consultation on design standards for electric utility connections for greenfield residential developments and associated maximum investment levels for 2023, May 31 2022.
228 Bulletin 2022-07, PDF pages 1-2.

Acquisition (SCADA).[229] The resulting 2023 forecast for the Environment, Safety and Reliability category exceeded the escalated 2018-2020 average by $4.7 million or 7.7 per cent. Fortis indicated that this increase in cost was driven by work related to Distribution Automation, which is a part of its SCADA program involving the installation of devices that can be operated remotely by system operators to isolate outages. Fortis identified that Distribution Automation was planned on a community basis, and that it based its forecast on the specific scope of work to be performed and the number of units to be installed, replaced or upgraded in 2023. The remainder of the SCADA program was forecast based on escalated historical average costs, for a total capital expenditure of $8.35 million in 2023.[230]

247. The SCADA program includes costs to retrofit or to install SCADA field equipment. Remote monitoring and control of reclosers and feeder tie-switches through SCADA enables Fortis to restore power faster for customers by reducing travel and switching time that would otherwise be associated with power restoration. SCADA also improves productivity associated with planned outages and live-line work.[231]

248. Fortis did not provide a business case for the SCADA program or any of the programs in the Environment, Safety and Reliability capital category because the variance between its 2023 forecast capital additions and the escalated 2018-2020 average of historical capital additions was less than the materiality threshold set out by the Commission.[232] In response to Commission questions, Fortis explained that the historical average number of units replaced, upgraded or installed for the SCADA program between 2018 and 2020 was insufficient to meet the forecast needs of the SCADA program in 2023, due to an expected increase in volume of new customer connections.[233] Fortis submitted that adding SCADA devices to its system, beginning in 2016, had resulted in reduced outage time and reduced outage restoration costs, and that additional SCADA infrastructure would be required to continue to provide these benefits as new customers connect to the system.[234]

249. As stated in the DSI report, the Commission recognizes that Alberta’s DFOs are taking steps to modernize their grids.[235] The Commission finds Fortis’s SCADA program to be an effective form of grid modernization that results in material benefits for the utility and for customers. In light of this, and given Fortis’s 2023 forecast capital additions for this category do not materially differ from the escalated 2018-2020 average, the Commission finds the costs associated with these additions to be reasonable. As directed in Section 5.2, Fortis must adjust its forecast for this program by using the approved escalation factors.

8.2.3 Forestry Protection – Wildfire Mitigation

250. Fortis is forecasting 2023 capital additions of $25.7 million for the Forestry Protection category. This category captures investments that Fortis has made and says it needs to make, to

229 Exhibit 26615-X0031, Fortis application, paragraph 332.
230 Exhibit 26615-X0201, FAI-AUC-2022JAN14-014(b).
231 Exhibit 26615-X0031, Fortis application, paragraph 325.
232 Decision 26354-D01-2021, paragraph 34.
233 Exhibit 26615-X0201, FAI-AUC-2022JAN14-014(d)-(f).
234 Exhibit 26615-X0201, FAI-AUC-2022JAN14-010(a)-(b).
235 Proceeding 24416, Distribution System Inquiry - Final Report, paragraph 18.

minimize the occurrence and severity of powerline-caused wildfires. The following table provides a breakdown of the Forestry Protection category into three individual programs and compares Fortis's historical capital additions to the 2023 forecast.

Table 13. Fortis historical and forecast capital additions – Forestry protection

Forestry protection programs	($ million)*										
	Actual								Forecast		
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Previously Trimmed Tree Removal	2.6	2.2	2.6	2.0	2.8	3.5	2.6	2.9	3.0	1.8	3.0
Forest Protection Area Maintenance	0.8	1.0	1.7	1.5	1.0	1.1	1.7	2.8	5.2	2.6	1.9
Wildfire Mitigation (new)	-	-	-	-	-	-	-	-	-	-	20.8
Total	**3.4**	**3.1**	**4.2**	**3.6**	**3.8**	**4.5**	**4.3**	**5.7**	**8.2**	**4.4**	**25.7**

Source: Exhibit 26615-X0031, Fortis application, tables 5-24, 5-26.
*Amounts shown are escalated to 2023 dollars. Minor variances occur due to rounding.

251. The Previously Trimmed Tree Removal program encompasses removal of trees near Fortis's distribution lines to eliminate the need to perform repetitive and regular tree trimming. According to Fortis, the removal of these previously trimmed trees improves reliability and reduces future operating costs associated with trimming at these locations. The Forest Protection Area Maintenance Program comprises removal of trees and widening of rights-of-way in forest protection areas, as defined by the Government of Alberta. Fortis stated that maintenance of these distribution lines is subject to the wildfire control agreement in place between Fortis and the Government of Alberta. Fortis explained that the Previously Trimmed Tree Removal and Forest Protection Area Maintenance programs were forecast based on the escalated 2018-2020 average of capital additions, while the Wildfire Mitigation Program (WMP) forecast capital additions were based on a bottom-up approach.

252. The WMP is a new initiative proposed by Fortis in this proceeding. It was informed by a wildfire risk identification analysis completed by Forsite Consultants Ltd. for Fortis in 2020. To help Fortis further understand and quantify the wildfire risks associated with its utility infrastructure, Forsite was engaged to "identify geographic areas across Fortis's service area where ignition(s) from a powerline may spread and grow into an impactful wildfire."[236]

253. The WMP consists of four individual projects:

(i) Hydraulic Recloser Replacement – this project includes the replacement of single-phase hydraulic reclosers in high-risk fire areas (HRFAs) with electronic SCADA enabled reclosers to enable remote access and automation. Fortis anticipates that this project, which started in 2021, will be completed by 2035. The forecast capital expenditures for 2023 are estimated to be $1.6 million.

(ii) Expulsion-type Fuse Replacement – this project includes the replacement of expulsion-type fuses with non-expulsion-based protection elements at or near the highest risk ignition points. Fortis stated that replacement of expulsion-based fuses

[236] Exhibit 26615-X0053, Appendix C-1, PDF page 4.

will be prioritized by highest risk location and completed over a seven-year period, starting in 2022. Forecast capital expenditures for 2023 amount to $1.7 million.

(iii) Early Fault Detection (EFD) Installation – this is a pilot project commencing in 2022, as EFD systems are relatively new, to investigate the use of advanced relay protection algorithms to detect damaged equipment, and broken or downed conductors in HRFAs. Fortis noted that the Electric Power Research Institute is also testing EFD systems and anticipates that it will use the shared data and findings to refine the pace of this project in 2023 and beyond. Forecast capital expenditures for 2023 are expected to be $7.7 million.

(iv) HRFA Rebuild – this project involves replacing end-of life conductors in HRFAs, as well as associated poles and hardware that have aged and are in poor condition. The project is expected to commence in 2023 with forecast capital expenditures of $9.8 million.

254. Fortis's 2023 forecast capital additions for the Forestry Protection category are $20.8 million higher than the escalated 2018-2020 average and exceed the materiality threshold as a result of the new WMP. In support of the drivers behind this program, Fortis provided a separate business case containing an overview of the program context, details on the need, scope and benefits associated with the WMP, related timing and costs, assessment of potential alternatives, and identification of risks and potential mitigating activities associated with the execution of the program.

255. Overall, Fortis asserted that the above investments would reduce the risk of wildfire ignitions caused by Fortis's system, and diminish the occurrence of significant losses and subsequent costs associated with such events.

256. The Commission finds the 2023 capital additions forecasts for the Previously Trimmed Tree Removal and Forest Protection Area Maintenance programs to be reasonable as they are generally in alignment with Fortis's historical spending undertaken while it was operating under the incentives of PBR. The Commission also finds Fortis's explanations of why the 2023 forecasts for the two programs deviated from the escalated 2013-2017 average capital additions and lowest cost capital year to be reasonable.

257. Much of the evidence filed by Bema Enterprises Ltd. on behalf of the CCA[237] with respect to Fortis's WMP failed to address the actual projects comprising the program (such as the hydraulic recloser replacement, expulsion-type fuse replacement and HRFA rebuild projects), and instead focused on matters that are related, but not directly relevant, to each of the projects. For example, the CCA's evidence focused on examining the nature of wildfire data collection practices by Fortis; assessing wildfire mitigation plans used by utilities in California, and other jurisdictions, and assessing their applicability to Alberta DFOs. The Commission did not find the CCA's evidence filed by Bema to be particularly helpful in evaluating Fortis's forestry protection programs and, specifically, each of the aforenamed projects comprising it.

[237] Exhibit 26615-X0310.02, 26615 CCA Wildfire Evidence ATCO and Fortis Alberta.

258. Nevertheless, all parties agreed that wildfire mitigation is a critically important issue that should be addressed by the utilities in general. The CCA, for example, stated that it is "not opposed to any specific, reasonable and supported wildfire mitigation strategy."[238] The UCA submitted that it "recognizes that wildfire mitigation is a serious issue that must be considered by utilities when operating their systems."[239]

259. Regarding the hydraulic recloser and expulsion-type fuse replacement projects, the Commission is of the view that these initiatives will improve Fortis's wildfire risk mitigation operations, result in operational efficiency and eliminate associated ignition sources. The CCA's expert witness, Dr. Russell, confirmed at the hearing that both technologies "have their place, and many utilities are doing both of those things."[240] Dr. Russell also confirmed in an IR response[241] that:

> There are many reasons to replace hydraulic reclosers with modern automatic circuit reclosers (ACRs)…. Given the broad benefits of ACRs, a replacement plan is warranted …
>
> … Expulsion fuses have long been known as a wildfire ignition mechanism. The operation of fuses is common during high wind conditions, which also enhance fire ignition and spread. Therefore, the industry has generally recognized that replacement of these fuses provides some benefit in wildfire prevention. Expulsion fuses are not allowed for use in certain jurisdictions in some states.

260. Accordingly, the Commission approves forecast capital expenditures for 2023 in the amounts of $1.6 million and $1.7 million for hydraulic recloser and expulsion-type fuse replacements, respectively.

261. There was general consensus with respect to the EFD installation project that this is a promising monitoring technology capable of preventing wildfires. Dr. Russell, for example, stated that "EFD has merits. EFD is a technology that works in a specific way and addresses a specific set of things. All tools are valuable to the extent that they can, you know, prevent wildfires, but you have to obviously consider the performance, benefits, cost, and the practical application of various technologies.… EFD has many advantages, as do other systems."[242] Dr. Marxsen noted that "EFD is a new technology that has been proven to detect and locate (to within ten metres) powerline defects before they become powerline faults."[243]

262. Nevertheless, considering that this is an emerging technology, the Commission views that Fortis approaching this project on a pilot basis is a practical course of action for testing EFD technology within its distribution system, prior to integrating the technology on a wider scale and systematic basis across Fortis's service territory. While the Commission is prepared to approve forecast capital expenditures for 2023 in the amount of $7.7 million, it does so on the condition that Fortis reports the pilot results as part of its first annual PBR3 rates adjustment filing. Further,

238 Exhibit 26615-X0482, CCA oral argument - Wildfire Issues, paragraph 18.
239 Exhibit 26615-X0476, UCA oral argument, paragraph 47.
240 Transcript, Volume 1, page 33, lines 10-16.
241 Exhibit 26615-X0401, CCA-AUC-2022MAR21-008(a)-(b), PDF pages 27-28.
242 Transcript, Volume 1, page 34, lines 12-21.
243 Exhibit 26615-X0418, Fortis rebuttal evidence of T. Marxsen, PDF page 5.

given the synergies discussed on the record of this proceeding between the EFD and DFA technologies, the Commission encourages Fortis to discuss, in the compliance filing to this decision, the feasibility of piloting DFA technology, concurrently with the EFD, as part of its 2023 budgeted $7.7 million.

263. Finally, the Commission is not persuaded that a material difference exists between the proposed HRFA Rebuild project and Fortis's present practice of rebuilding lines based on pole failure and conductors that have reached end of life. According to Fortis,[244] there are currently 8,600 km of end-of-life conductor that require replacement as part of the existing reliability program. This backlog is expected to continually grow by approximately 300 km per year. A major part of the wildfire mitigation strategy is to accelerate the pace of end of life conductor replacement in HRFAs. Fortis intends to accomplish this "independently from the existing reliability program to avoid conflicts with the existing program's planning cycle, timelines, and pace"[245] and commence the project in 2023 with 105 km of end-of-life conductor replaced annually. The Commission has several concerns with Fortis's approach.

264. In response to a Commission IR,[246] Fortis informed the Commission that it identified the backlog in 2018 and initiated the conductor management program to address end of life replacements at that time. It is unclear to the Commission why, with the presence of that program, Fortis still requires an analogous "new" program to address the same core issue. The criteria that guides the "targeted replacement" of conductors in the HRFAs should also inform the order and pace of asset replacement in the existing Fortis end of life program. It is also unclear to the Commission why this new program is being undertaken in 2023 rather than having been initiated much earlier given that Fortis has been aware of the underlying issue for years.

265. In light of the foregoing, the Commission denies Fortis's request for 2023 forecast capital expenditures of $9.8 million associated with its HRFA Rebuild project. In making this decision, the Commission notes that Fortis indicated "the current backlog has not created an imminent operational risk of ignition events" and that Fortis "has no evidence that its EOL [end of life] conductor replacement approach has contributed to an increased risk of wildfire ignition due to conductor breakage."[247]

266. The CCA and the UCA submitted that Fortis's WMP does not define target outcome and program scope carefully, does not consider cost constraints and cost effectiveness, and that data is manually connected and is not categorized by geographic area.[248] The Commission agrees that Fortis's evidence in this proceeding neither demonstrates that it evaluates the performance of its WMP, nor that it collects data in a format that can later be analyzed when a wildfire does occur.[249] Therefore, the Commission directs Fortis to provide, in the compliance filing, a cost-

244 Exhibit 26615-X0035, Appendix C - Wildfire Mitigation Program, PDF page 37.
245 Exhibit 26615-X0035, Appendix C- Wildfire Mitigation Program, PDF page 37.
246 Exhibit 26615-X0201, FAI-AUC-2022JAN14-025(i).
247 Exhibit 26615-X0201, FAI-AUC-2022JAN14-025(c), (f).
248 Transcript, Volume 5, page 748, line 25, page 749, lines 1-5 (CCA argument, J. Wachowich); Transcript, Volume 5, page 799, lines 10-25, page 800, lines 1-25, page 801, lines 1-24 (UCA argument, K. Rutherford).
249 For example, when asked by the UCA about data on wildfires Fortis provided Alberta-wide data from the Wildfire Management Branch of Alberta Agriculture, Forestry, and Rural Economic Development on

effective proposal to monitor the progress of its WMP and measure the effectiveness of the related capital expenditures. The proposal should include processes and procedures required to (i) track and report all details relating to wildfire incidents; (ii) identify the measures to be implemented to resolve the incidents; and (iii) assess the effectiveness of those measures in mitigating the incidents.

8.2.4 General Support

267. Fortis is forecasting capital additions for the General Support category of $67.2 million in 2023. According to Fortis, this category captures capital investments that are largely cyclical in nature, which Fortis has made and will be required to make to support ongoing operations including facilities, upgrades and improvements to land and structures, work equipment, tools, communication equipment, computer hardware and software.[250] The following table provides a breakdown of the General Support category into five individual programs and shows Fortis's historical capital additions in comparison to the 2023 forecast.

Table 14. Fortis historical and forecast capital additions

General support programs	Actual								Forecast		
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	($ million)										
Facilities	16.5	5.5	11.1	14.9	29.0	5.1	10.9	16.1	13.9	24.1	10.8
Tools and instruments	2.0	2.6	3.6	4.8	6.2	2.3	2.7	3.7	4.0	2.5	2.7
Transportation equipment	5.6	9.5	16.0	18.4	18.7	17.6	9.1	14.0	8.8	11.5	12.7
Information Technology – Hardware	12.3	6.4	7.0	8.5	8.5	12.0	6.0	6.1	8.5	6.2	8.4
Information Technology – Software	19.7	15.2	13.7	29.9	9.3	21.7	20.1	27.9	29.2	36.0	32.8
Total	**56.1**	**39.2**	**51.5**	**76.5**	**71.7**	**58.7**	**48.8**	**67.8**	**64.4**	**80.3**	**67.2**

Source: Exhibit 26615-X0031, Fortis application, tables 5-28, 5-32, 5-34, 5-36, 5-38, 5-40.
*Amounts shown are escalated to 2023 dollars.

268. Fortis provided explanations for each program and outlined its approach to forecasting, as briefly summarized below:

- The forecast for the Facilities program was determined using a three-year average of historical costs, adjusted for inflation. Specific initiatives were determined according to business need with contributing estimates driven by project requirements, such as the acquisition of land, new construction, and renovations.[251]

January 19, 2022, and was unable to provide any data to distinguish wildfires caused by individual distribution or transmission facilities. See Exhibit 26615-X0204, FAI-UCA-2022JAN14-018(a-c). In response to an IR from the CCA, Fortis confirmed that it does not categorize data by geographic areas, and that such data could not be provided with a reasonable effort. Fortis was also unable to provide information on the location, date and size of fires. See Exhibit 26615-X0221, FAI-CCA-2022JAN14-036(b), (d) and (f).

250 Exhibit 26615-X0031, Fortis application, paragraphs 391, 401.

251 Exhibit 26615-X0031, Fortis application, paragraph 402.

- Fortis's Tools and Instruments program was generally based on the escalated 2018-2020 average capital additions,[252] but was adjusted for large one-time purchases.[253]

- The Transportation Equipment program was based on the units of vehicles identified for replacement that have reached the end of their service lives or changes in the fleet configuration to support Fortis's operational productivity.[254]

- IT hardware and software programs were forecast using a combination of escalated historical averages for licensing and a zero-based (bottom-up) approach incorporating required lifecycle updates and replacements, as well as new applications to support Fortis's operations processes and cybersecurity requirements, considering historical costs for projects of a similar nature.[255]

269. The IT Hardware program comprises a significant portion of the General Support category. It addresses the replacement of hardware equipment on a regular cycle to support Fortis's operations. Replacement cycles vary according to the nature of the equipment involved with proportionate replacements being completed in any given year. This program includes general hardware replacements for servers, storage, desktops/laptops, data and telecommunication networks, telephones, printers, as well as for disaster recovery. Lastly, the IT Software program includes investments in key applications for Fortis; for example, SAP and Microsoft, which support critical business processes and utility services. This program includes the purchase and implementation of new, and the life-cycle replacement of existing, IT software.[256]

270. The forecast 2023 capital additions for the General Support category are greater than the escalated 2018-2020 average and exceed the capital materiality threshold on an overall basis. The following table shows which individual programs are above/below the threshold.

Table 15. Assessment of program materiality for General Support category

General support programs	2018 to 2020 Average*	2023 Forecast	Variance	Variance	Exceeds materiality**
	($ million)			(%)	
Facilities	10.7	10.8	0.1	0.6	No
Tools and instruments	2.9	2.7	(0.3)	(8.9)	No
Transportation equipment	13.5	12.7	(0.8)	(6.2)	No
Information Technology – Hardware	8.0	8.4	0.3	4.1	No
Information Technology – Software	23.2	32.8	9.5	41.0	Yes

Source: Exhibit 26615-X0031, Fortis application, PDF page 133.
* Amounts shown are escalated to 2023 dollars.
** Materiality threshold established as $5 million or 10% and having a dollar amount greater than $1 million. Minor variances due to rounding.

252 Exhibit 26615-X0031, Fortis application, paragraph 402.
253 Exhibit 26615-X0444, FAI-AUC-2022APR12, PDF page 7.
254 Exhibit 26615-X0031, Fortis application, paragraphs 395, 402.
255 Exhibit 26615-X0031, Fortis application, paragraph 402.
256 Exhibit 26615-X0031, Fortis application, paragraphs 396-397.

271. The Commission has reviewed Fortis's 2023 capital additions forecast for the General Support category and finds that the forecasts of individual programs outlined above that do not exceed the materiality threshold are reasonable and generally aligned with historical spending, which was undertaken while Fortis was operating under the incentives of PBR.

272. The IT Software program exceeded the materiality threshold and resulted in a variance of 41 per cent when compared to the escalated 2018-2020 average of capital additions. To better explain which specific subprograms of the IT Software program exceeded the materiality threshold, Fortis provided a separate business case comprising its forecasting methodology, the analysis of alternatives considered and explanations of each subprogram planned for implementation in 2023. The subprograms consist of: (i) other software applications; (ii) SAP software; and (iii) major software applications, with the latter subprogram exceeding the escalated 2018-2020 average and the capital materiality threshold.

273. During the hearing, Fortis explained that it had developed a road map in 2017 to address its long-term technological business requirements by way of sequential upgrades and enhancements until 2027. Fortis indicated that 2023 is the final year for (i) the implementation of the mobile workforce management system, which is a single system to schedule, dispatch and manage all of Fortis's field work; and (ii) replacement of the legacy geographic information system (GIS) environment with the current industry standard, Esri-based GIS system.[257]

274. The Commission has reviewed the evidence filed by Fortis in support of the 41 per cent variance and has considered the clarification provided at the oral hearing. The Commission notes that the costs to implement the mobile workforce management systems and the replacement of the legacy GIS, which will be incurred in 2023, are part of a larger roadmap that Fortis projects will take until 2027 to complete. The Commission understands that these two initiatives are part of a broader program and is persuaded that the associated 2023 costs happen to fall in a rebasing year and were not deliberately designed to be incurred in a rebasing year. The Commission finds that Fortis's detailed evidence on this program satisfactorily supports the IT Software program's 2023 forecast and finds the forecast to be reasonable.

275. In light of the foregoing, the Commission approves the General Support category forecast of $67.2 million for 2023 as filed, subject to forecast adjustments to incorporate the approved escalation factors described in Section 5.2.

8.2.5 Metering

276. The metering category captures investments that Fortis makes to support accurate billing and load settlement by providing actual consumption data to the billing system, the load settlement system, retailers, and customers.[258] Fortis indicated metering was made up of a single program titled "Sustainment and Growth Metering." Fortis forecast capital additions of $19.9 million for this program in 2023.

277. A major program in this category is Fortis's Next Generation Advanced Metering Infrastructure (AMI) Program. AMI is an integrated system of meters, communications networks

[257] Transcript, Volume 1, pages 147-154 (R. Tsidale).
[258] Exhibit 26615-X0031, Fortis application, paragraph 357.

and data management systems that enable automated meter reading and two-way communication between a meter and the utility's head-end systems. AMI meters record customer energy and demand data, along with voltage and current data, providing visibility of the distribution system at an individual site level. In this application, Fortis requested approval for costs to upgrade its existing Power Line Carrier (PLC) and 3G Cellular AMI systems.

278. In 2024, Fortis's current AMI vendor will be ceasing production of the PLC technology used by Fortis for its current AMI system. Fortis was able to negotiate continued supply of PLC AMI meters until 2024 and operational support for the PLC AMI system until the end of 2029.[259] In addition to its PLC meters, Fortis uses cellular AMI meters on a 3G communication network.[260] As decommissioning of 3G cellular networks in Alberta is planned to begin in 2023, Fortis anticipates the need to transition to a new metering system that uses a combination of radio-frequency and cellular technology, and can replace both the existing PLC and 3G AMI systems.

279. Fortis indicated its new AMI system would have advanced capabilities that include bi-directional metering (allowing for the integration of distributed energy resources), subhourly interval data capability, remote upgrades, tamper detection, integrated disconnect and reconnect capability, and measurement of power quality.[261] Fortis stated that, in most jurisdictions, AMI systems with interval-capable AMI meters are considered standard utility assets.

280. Fortis's proposed new AMI system would include: (i) the lifecycle replacement of existing meters with bi-directional, interval-capable AMI meters; (ii) the provision of communication network(s) covering 100 per cent of Fortis's meters by the end of 2029; and (iii) implementation of a single head-end system, integrated with meter data management systems to support load settlement, billing and non-billing systems (both existing and future). Planning and procurement for the new AMI system commenced in 2021 and included issuing a Request for Proposal (RFP) to select a vendor and AMI technology. Fortis's AMI upgrade program is to be executed in two phases. In the first phase (2022-2024), Fortis will evaluate the new AMI system and, in the second phase (2024-2029), will carry out the lifecycle replacements. Fortis requested and received approval to keep the forecast budget and detailed schedule of this project confidential.[262]

281. Fortis forecast metering-related capital additions of $19.9 million in 2023, which is $3.7 million higher than its escalated 2018-2020 average. Fortis indicated that this variance is driven by the need to upgrade the AMI system, as described above. Specifically, in 2023 Fortis expects to implement the head-end system and radio-frequency network, and to install approximately 15,000 new meters. Fortis's forecast is based on a bottom-up estimate of all metering related costs, including addressing customer growth and Measurement Canada requirements, and upgrading the new AMI system. As Fortis had not yet completed the RFP

259 Exhibit 26615-X0201, FAI-AUC-2022JAN14-017(a).
260 Exhibit 26615-X0036, Appendix D, AMI Business Case - Redacted, PDF page 3.
261 Exhibit 26615-X0201, FAI-AUC-2022JAN14-018(b).
262 Exhibit 26615-X0056, AUC letter - Ruling on Fortis motion for confidentiality, November 23, 2021.

process for the new AMI system at the time of filing its application, costs were based on current vendor pricing and Fortis's experience.[263]

282. Fortis could not confirm that the legacy meters and other equipment related to the legacy PLC AMI system would be fully depreciated at the time of replacement.[264] Fortis incorporated a forecast 2023 depreciation expense placeholder in its application, which included the impacts of Fortis's plans around metering assets and aligning the recovery of the existing investment with the estimated timing of asset removal. Fortis indicated that it will file a depreciation study upon completion of the 2023 COS review process, and the depreciation placeholders included in this application will be updated to reflect the approved depreciation parameters. In Section 5.4.4, the Commission approves this approach.

283. The Commission has reviewed both the confidential and public information provided by Fortis on its forecast metering expenditure for the proposed upgrade to a new AMI system. The Commission finds there is a need to complete the metering work captured in this program, including the upgrade to a new AMI system, to respond to vendors' discontinuation of Fortis's current metering technology. The program will result in Fortis having an AMI system that aligns with North American and Alberta trends in AMI technology. No party raised concerns regarding the need for Fortis's proposed AMI upgrade.

284. This program represents a large-scale replacement of meters over the PBR3 term and is a significant undertaking for Fortis. However, Fortis is forecasting costs that are generally in line with its escalated 2018-2020 average. The Commission finds that Fortis's approach to upgrading its AMI system balances the need to complete a mass replacement of existing metering infrastructure against the need to manage rate impacts to customers. Fortis's proposal will allow for the upgrade of its AMI system without resulting in a sudden step change in capital additions. An increase in capital additions of $3.7 million is reasonable, given the scope of the project proposed by Fortis. As such, the Commission approves the applied-for capital additions for the metering category, including the costs for the new AMI system, subject to incorporating the adjustments to escalation factors described in Section 5.2.

8.2.6 Distribution Voltage Management (new program for Externally Driven System Modifications)

285. Fortis proposed a new Distribution Voltage Management Program (DVM program), to be initiated in 2022. This program will mitigate secondary voltage violations caused by increased Distributed Energy Resources (DERs)[265] penetration and enable Fortis to optimize distribution system voltage to achieve line loss and system peak reductions.[266] Fortis indicated that these outcomes are aligned with Fortis's obligations under the *Electric Utilities Act* to manage line losses and to maintain safe and reliable service for all customers connected to Fortis's distribution system.

---

[263] Exhibit 26615-X0036, Appendix D - AMI Business Case - Redacted, PDF pages 29-30.
[264] Exhibit 26615-X0201, FAI-AUC-2022JAN14-017(c).
[265] "DERs are defined to include any technology that is connected to the distribution grid and affects the supply of and/or demand for electricity." Proceeding 24116, Distribution System Inquiry Final Report, paragraph 12.
[266] Exhibit 26615-X0037, Appendix E, Distribution Voltage Management, PDF page 3.

286. Fortis pointed to a significant increase in DERs penetration in its service territory as driving the need for the DVM program. As of October 2021, Fortis has connected over 2,500 DERs sites with a total cumulative capacity of over 600 megawatts.[267] The average total capacity of Distributed Generation (DG)[268] connections in 2020 and 2021 was 6.5 times higher than the 10-year average.[269] Fortis's existing voltage management practices were originally designed for one-way grid operation, which assumed voltage magnitude would decrease with distance.[270] However, DERs can cause voltage increases on the distribution system, and can result in voltages that exceed the maximum levels set out in CSA standards.[271]

287. Fortis indicated that going forward, the DVM program will be a recurring program and, consequently, will be included in the Environment, Safety and Reliability category in future proceedings. The DVM program consists of four project streams that will (i) create near real-time visibility of system voltage profiles; (ii) implement solutions to mitigate over-voltages on the secondary (low voltage) system; (iii) implement solutions to manage primary system voltage or power quality issues; and (iv) optimize system voltages using Conservation Voltage Reduction (CVR) to minimize line loss and create energy conservation savings for customers.[272]

288. Fortis forecast 2023 capital additions of $7.8 million for the DVM program. Fortis developed its forecast using a bottom-up methodology, based on the costs of solutions to be implemented in each project stream. For 2023, Fortis forecast $2.1 million in capital expenditures for the real-time visibility stream, $0.1 million for the mitigation of secondary system issues, $2.6 million for mitigation of primary system issues and $3 million for optimization of system voltages.

289. Through IRs and the hearing process, the Commission queried Fortis on why it had not initiated work related to the DVM program during the PBR2 term. Fortis indicated that there had not been a need for the program previously, as it was driven by the recent step change in DER interconnections in 2020 and 2021.[273] As described above, increased penetration of DERs is the main driver for the program, and Fortis indicated that voltage issues caused by DERs are only now becoming more prevalent. Fortis also indicated that the technology itself has only recently matured, and that Fortis used the recent pilot of CVR by the Lethbridge Electric Utility to expand its own knowledge of CVR.

290. The Commission finds that the DVM program offers a reasonable solution to support Fortis in the continued safe and reliable operation of its distribution system as penetration of DERs increases, and finds the forecast capital additions of $7.8 million to be reasonable. Fortis has adequately justified the timing of the program, based on the maturity of CVR technology and the level and timing of DER penetration on Fortis's distribution system. Interveners raised few, if any, significant concerns regarding this program. The Commission approves the forecast capital

[267] Exhibit 26615-X0037, Appendix E, Distribution Voltage Management, PDF page 14.
[268] DER that do not qualify as micro-generators based on the criteria laid out in the micro-generation regulation.
[269] Exhibit 26615-X0478, Fortis Alberta Written Version of Oral Argument, paragraph 101.
[270] Exhibit 26615-X0037, Appendix E, Distribution Voltage Management, PDF page 8.
[271] Exhibit 26615-X0037, Appendix E, Distribution Voltage Management, PDF page 22.
[272] Exhibit 26615-X0037, Appendix E, Distribution Voltage Management, PDF pages 3-4.
[273] Exhibit 26615-X0201, FAI-AUC-2022JAN14-030(a).

additions of $7.8 million for the DVM program, subject to adjusting the forecast for this program using the escalation factors approved in Section 5.2.

8.2.7 System Purchases

291. Fortis applied for $15 million in 2023 forecast capital additions for the acquisition and transfer of small electricity distribution systems from other incumbent owners that have decided to discontinue their operations, including REAs and rural municipalities. The following table shows Fortis's historical system purchases in comparison to its 2023 forecast.

Table 16. Fortis historical and forecast system purchases

	Actual								Forecast		
	($ million)										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capital expenditures	-	-	21.1	-	(0.5)	3.8	4.8	-	-	13.0	15.0
Construction work in progress	-	-	-	-	-	-	-	-	-	-	-
Capital additions	-	-	21.1	-	(0.5)	3.8	4.8	-	-	13.0	15.0
Escalated capital additions	-	-	29.6	-	(0.6)	4.8	5.8	-	-	13.4	15.0

Source: Exhibit 26615-X0031, Fortis application, PDF page 148.

292. Fortis described its forecast methodology as one based on its "knowledge of the composition of various small distribution systems situated in and around its service area, as well as the content of recent discussions it has had with certain incumbent owner/operators."[274] In its application, Fortis highlighted that the cost drivers for the System Purchases category are "neither predictable nor stable" as owners of small electricity distribution systems that wish to cease operations approach Fortis based on their own unique operational and timing requirements. Based on this knowledge and these discussions, Fortis stated that it expects to potentially accept the transfer of distribution system assets valued at approximately $13.0 million in 2022 and participate in similar transactions having a value of approximately $15.0 million in 2023.

293. The Commission has reviewed the information provided by Fortis in respect of acquisition and transfer of small electricity distribution systems in 2023 and finds such information to be vague and unhelpful. In particular, the Commission is not persuaded by Fortis's forecasting methodology, as it provides inadequate factual support to permit the Commission to assess how Fortis arrived at the amount of $15.0 million and whether that amount is reasonable in the circumstances.

294. A Commission IR[275] requested that Fortis provide any additional quantifiable information that may assist the Commission in understanding how Fortis developed its 2023 forecast for system purchases. Fortis briefly outlined its valuation approach for assessing potential acquisition assets instead of providing details on how the $15 million was derived. In addition, Fortis expressly stated that it cannot provide firm assurances to the Commission that it will be required to accept the transfer of small distribution systems in 2023.[276] Further, while Fortis confirmed receiving expressions of interest from REAs located in its service area, Fortis

[274] Exhibit 26615-X0031, Fortis application, paragraph 454.
[275] Exhibit 26615-X0201, FAI-AUC-2022JAN14-029.
[276] Exhibit 26615-X0201, FAI-AUC-2022JAN14-029(c).

provided no evidence in support of this assertion. The Commission also notes the unpredictable pattern of Fortis's acquisitions since 2013, during which time there were five years with no transactions.

295. Fortis has suggested that a deferral mechanism approach would be a feasible means of addressing uncertainty in the timing and magnitude of future system transfers. However, in the absence of concrete supporting evidence, the above discussed factors describe no more than a potential transaction. The Commission agrees with the position of the UCA[277] that setting the deferral account to zero dollars would allow Fortis to recover amounts incurred in relation to a system purchase if one were to occur, but it would not require customers to contribute costs towards an expense that Fortis has failed to demonstrate is likely or reasonably likely to occur.

296. In light of the foregoing, Fortis's request for approval of 2023 forecast capital additions of $15 million for the acquisition and transfer of small electricity distribution systems is denied. However, Fortis is granted deferral account treatment for any system purchase transactions in 2023. If any such transactions take place in 2023, Fortis can bring this matter to the Commission for its consideration as part of Fortis's first annual PBR3 rates adjustment filing. To be clear, the deferral account treatment only applies in 2023. Consistent with the determinations in Decision 24405-D01-2019,[278] any system purchase transactions during the PBR3 term should be funded in accordance with the established PBR3 framework.

8.2.8 Secondary Upgrades (new program for Externally Driven System Modifications)

297. Fortis proposed the addition of a new Secondary Upgrades Program as part of the Externally Driven System Modifications forecast. Fortis indicated that this program was required to support electrification of residential services, and would enable residential customers to upgrade their electrical services at a lower cost while also enabling Fortis to execute more efficient solutions for secondary distribution service upgrades.[279]

298. This program is made up of two projects: one for single service upgrades, and one for secondary network upgrades. The single service upgrade project involves completing individual upgrades to existing customer connections to accommodate service upgrade requests.[280] The secondary network upgrades project involves completing larger scale secondary network upgrades within a delimited area, to enable cost-efficiencies and minimize disruptions for customers.[281]

299. The 2023 forecast capital additions for this program are $5.4 million, based on the individual forecast for each of the two projects included within this category. Fortis forecast $4.2 million in capital expenditures for the single service upgrade project in 2023, based on the forecast need to complete 306 single service upgrades and $1.1 million in capital expenditures in 2023 for the secondary network upgrade project, based on the forecast need to complete

277 Exhibit 26615-X0476, UCA oral argument, paragraph 17.
278 Decision 24405-D01-2019: Generic Proceeding to Review Rate Treatment of Distribution System Acquisition Costs Under Performance-Based Regulation, Proceeding 24405, September 6, 2019.
279 Exhibit 26615-X0038, Appendix F - Secondary Upgrades program business case, PDF page 3.
280 Exhibit 26616-X0038, Appendix F - Secondary Upgrades program business case, PDF page 3.
281 Exhibit 26616-X0038, Appendix F - Secondary Upgrades program business case, PDF page 4.

55 secondary network upgrades. For both projects, the forecast count of upgrades to be completed was based on a linear projection of historical upgrade requests received by Fortis, as well as the projected rate of EV adoption within Fortis's territory.

300. The Secondary Upgrades Program was not included in an existing cost category because Fortis felt its focus on customer service requests related to secondary service upgrades differentiated it from existing categories such Rebuilds, Replacements and Life Extensions or Environment, Safety and Reliability.[282] Specifically, Fortis proposed the need for the program based on the increasing number of requests for service upgrades it received. Fortis received 497 service upgrade requests between 2018 and 2021, with 308 of those requests occurring in 2021.[283] Fortis predicted that increasing use of air conditioners, EV adoption and load increases associated with working from home were all factors that were expected to increase customer demand for service upgrades in the future.[284]

301. The single service secondary upgrades project involves Fortis completing individual service upgrades as requested by a customer, at no cost to the customer. This represents a change from current Fortis practices, as currently all costs associated with service upgrades are passed along to the customer. Fortis forecast capital expenditures of $4.2 million in 2023 for this project.

302. The secondary network upgrade project involves replacing the entire network of secondary cables originating at a transformer or pedestal at the time when an individual service upgrade is completed. Fortis estimated that replacing the entire network can reduce future service upgrade costs by up to 30 per cent.[285] Fortis forecast $1.1 million in capital expenditures for this project in 2023.

303. The Commission denies the proposed program, on the basis that the single service secondary upgrade project does not align with ratemaking principles, and the secondary network upgrade program does not represent a new, or non-recurring, program. Further the Commission is not persuaded that the secondary network upgrade project does not duplicate the escalated costs of existing programs, as outlined further below.

304. The Commission finds that allocating the costs for the single service secondary upgrades, which are attributable to individual customers, to all ratepayers does not align with cost-causation principles and does not send appropriate price signals to incent end-use customers to choose the most economical connection solution. Such a program increases costs for all customers while offering benefits only to the individuals receiving service upgrades.

305. The Commission does not support the categorization of the secondary network upgrade project as new and non-recurring. As indicated in Fortis's business case and IR responses, Fortis completed service upgrades during the PBR2 term, and therefore the Commission is not persuaded that the costs associated with the secondary network upgrades required to support

282 Exhibit 26616-X0201, FAI-AUC-2022JAN14-036(a).
283 Exhibit 26616-X0038, Appendix F - Secondary Upgrades program business case, PDF page 5.
284 Exhibit 26616-X0038, Appendix F - Secondary Upgrades program business case, PDF page 3.
285 Exhibit 26615-X0038, Appendix F - Secondary Upgrades program business case, PDF page 17.

these service upgrades are not otherwise accounted for under Fortis's existing Externally Driven System Modifications Program. To approve Fortis's request for additional capital for a new program would be duplicative of the capital already provided in the Externally Driven System Modifications Program. Further, given that escalated 2018-2020 average capital additions were an input into Fortis's forecast for the Externally Driven System Modifications Program, the Commission sees no need to provide additional capital for this scope of work. The Commission expects that Fortis can continue to support such requests through funding provided for its recurring programs, as it has throughout the PBR2 term. The Commission directs Fortis to exclude the costs of the Secondary Upgrades Program from its 2023 forecast capital additions.

306. The Commission notes that this should not be taken as a rejection of the proactive approach to secondary network upgrades described by Fortis in its business case. Fortis has described clear efficiencies that can be achieved through a proactive approach, and the Commission finds that it would be reasonable for Fortis to continue to incorporate such an approach into its existing upgrade practices.

8.2.9 Remote Community Reliability Program

307. Fortis proposed the addition of a new Remote Community Reliability Program beginning in 2023. This program is required to provide increased reliability to remote communities that experience below average reliability.[286] Under this program, Fortis would use Battery Energy Storage Systems (BESS) to supply remote communities during outages, therefore reducing outage times. Fortis has suggested that the use of BESS offers a more cost-effective alternative to traditional solutions.[287]

308. Fortis forecast $2.1 million in capital additions for this program in 2023, based on the need to implement BESS in the communities of Heart Lake First Nation and Jean Baptiste Gambler reserve. The forecast costs for this program were benchmarked against Fortis's Waterton Energy Storage Project, and assume a two per cent annual decrease in battery costs.[288] The BESS installed in Heart Lake First Nation would be sized at 477 kW peak capacity, and would cost $1.2 million to implement.[289] The BESS installed in Jean Baptiste Gambler reserve would be sized at 217 kW peak capacity, and would cost $0.9 million to implement.[290] These costs include the unit cost of the battery itself, a microgrid controller for the BESS, and the civil and wires infrastructure required to connect the BESS and implement microgrid control. Fortis also identified a third community at which it proposed to install a BESS system in 2024 at a cost of $1.76 million.[291]

309. The Commission denies this proposed program. Fortis has not met the criteria established by the Government of Alberta in Bill 22 for distribution utilities to own and operate an energy storage facility. Bill 22 passed third reading on May 12, 2022, and received Royal Assent. Once in force, it will effect amendments to the *Electric Utilities Act*, including compelling distribution

286 Exhibit 26615-X0031, Fortis application, paragraph 471.
287 Exhibit 26615-X0040, Appendix H – Remote Community Reliability business case, PDF page 20.
288 Exhibit 26615-X0040, Appendix H – Remote Community Reliability business case, PDF page 8.
289 Exhibit 26615-X0040, Appendix H – Remote Community Reliability business case, PDF page 14.
290 Exhibit 26615-X0040, PDF page 16.
291 Exhibit 26616-X0040, PDF page 19.

utilities to obtain Commission approval before owning and operating an energy storage facility such as BESS. Under Bill 22, a utility can only own and operate an energy storage facility under a limited set of criteria.[292]

310. Although Fortis stated that it "will align this program with future policy and rules regarding the treatment of energy storage,"[293] it has also confirmed that it has not solicited competitive bids for a comparable service,[294] which is one of the criteria included in Bill 22.[295] While Bill 22 has not come into force at the time of writing this decision, it clearly sets out the government's policy intentions with respect to distribution utilities owning and operating energy storage facilities. In this policy context, it is the Commission's view that it is not reasonable to include these costs as part of Fortis's 2023 forecast revenue requirement.

311. Accordingly, the Commission directs Fortis to remove the 2023 forecast capital additions for the Remote Community Reliability Program in its compliance filing. The Commission notes that the treatment of capital related to grid modernization and net-zero policies in PBR3 was included in the draft list of issues for Proceeding 27388.[296]

8.3 ATCO Electric 2023 forecast capital additions

312. ATCO Electric used a hybrid approach in forecasting its 2023 capital additions. Its hybrid approach consisted of a combination of mechanistic forecasts, which were based on the escalated 2018-2020 average capital additions, and non-mechanistic forecasts, using a bottom-up forecasting methodology, to arrive at the overall capital forecast.[297] For some programs, ATCO Electric used both methods (i.e., it forecast costs using the mechanistic approach for some projects within a capital grouping and used the non-mechanistic approach for other projects within that capital grouping).

313. Consistent with Decision 26354-D01-2021,[298] ATCO Electric categorized[299] its capital projects as either recurring or non-recurring. Recurring capital projects are predictable and are expected to occur in the future. Non-recurring capital projects are either new, not part of ATCO Electric's ongoing business operations, projects whose drivers have changed or where costs are not forecast to continue to be incurred beyond 2023.

314. ATCO Electric forecast its capital additions as shown in the table below.[300]

---

292 Bill 22, *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act, 2022*, 3rd Sess., 30th Leg., Alberta, 2022 (hereinafter "Bill 22"), cl. 3(12).
293 Exhibit 26615-X0201, FAI-AUC-2022JAN14-037, PDF page 118.
294 Exhibit 26615-X0201, FAI-AUC-2022JAN14-037, PDF page 118.
295 Bill 22, cl. 3(12).
296 Proceeding 27388, Exhibit 27388-X0020, AUC letter - Preliminary list of issues and directions on procedure, June 17, 2022, PDF page 5.
297 Exhibit 26615-X0023, ATCO Electric application, PDF page 47, paragraph 151.
298 Decision 26354-D01-2021, paragraph 30(iii)-(iv).
299 Exhibit 26615-X0023, ATCO Electric application, PDF pages 46-47, Section 7.1.2.
300 Exhibit 26615-X0023, ATCO Electric application, PDF page 43, paragraph 137.

Table 17. ATCO Electric 2020-2023 forecast capital additions

Capital grouping	2020A	2021F	2022F	2023F	Forecast methodology
	($000)				
Externally Driven System Modifications	15,920	16,693	17,160	17,627	Mechanistic
Customer Growth – New Extensions	103,220	105,128	112,308	118,597	Non-mechanistic
Environment, Safety and Reliability	5,011	7,748	7,965	8,181	Mechanistic
Forestry Protection	19,305	25,000	28,313	29,383	Non-mechanistic except for Clearance and Safety activity
Metering	7,301	9,104	9,358	9,613	Mechanistic
Rebuilds, Replacements and Life Extensions	33,578	42,743	46,030	47,982	Overhead line rebuilds: Non-mechanistic Pole replacements and underground: Mechanistic
General Support	33,833	29,642	33,760	37,129	Transportation Equipment: Non-mechanistic Buildings, Communication Structures & Equipment, Tools & Instruments, Information Technology: Mechanistic
CIS Replacement*			70,111		Non-mechanistic
Grid Modernization**	685	6,878	27,915	39,105	Non-mechanistic
Total	218,853***	242,936	352,920	307,617	

Source: Exhibit 26615-X0024, Appendix A, ATCO Electric Commission Template, Schedule 4.1a.
*CIS Replacement costs will be addressed in the decision in Proceeding 26616 for both ATCO Electric and ATCO Gas.
**This capital program will be classified as recurring subsequent to 2023.
*** Net of distribution to transmission contributions.

8.3.1 Programs that were forecast using a mechanistic approach

315. The Commission approves the use of the mechanistic approach by ATCO Electric 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 Electric’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.

316. For these reasons, the Commission finds that ATCO Electric’s capital additions forecasts derived using the mechanistic approach, as adjusted by the escalation factors approved in Section 5.2, are reasonable. The Commission directs ATCO Electric to recalculate its 2023

capital additions forecast under the mechanistic approach to reflect the escalation factors approved in Section 5.2 of this decision.

8.3.2 Programs that were forecast using a non-mechanistic approach

317. The Customer Growth – New Extensions, Forestry Protection, Line Rebuilds, Replacements and Life Extensions, General Support and Grid Modernization programs that were forecast using a non-mechanistic approach are addressed in the following sections. However, as noted in the sections that follow, for some projects within these programs ATCO Electric used the mechanistic approach.

318. The Commission approves the use of the non-mechanistic approach by ATCO Electric to develop the forecasts for those capital additions that were expected to materially differ from historical average expenditures incurred in PBR2. The capital additions in this category were generally adequately supported with detailed business cases that consisted of project drivers and benefits, project costs broken down into various subcategories, and evaluation of viable alternatives considered. The Commission found this additional information to be helpful and necessary, thereby allowing it to conduct a thorough review of the capital additions in this category, as presented in the remainder of this section.

8.3.2.1 Customer Growth – New Extensions

319. This program is used to accommodate growth in new residential, farm, commercial and industrial customers by connecting them to ATCO Electric's distribution system in accordance with sections 105 and 127 of the *Electric Utilities Act* and ATCO Electric's Terms and Conditions. This program includes new extension projects grouped into two categories: small new extensions (individual projects of less than $1,000,000), and large new extensions (individual projects in excess of $1,000,000).[301]

320. ATCO Electric used gross domestic product (GDP) projections for Alberta to forecast 2023 capital additions for this program.[302] This is a change from ATCO Electric's historical practice which consisted of forecasting new extensions by customer type using data provided from current customers, prospective customers, municipalities and developers and housing start projections.[303] However, in the current economic environment, large new extension customers have been less certain in committing to new electric facilities.[304] For small new extensions, ATCO Electric chose not to rely on Canada Mortgage and Housing Corporation housing starts data because that data is no longer disaggregated for large municipalities in ATCO Electric's service territory.[305] As an alternative, ATCO Electric determined that using Alberta GDP was appropriate, because it reflects the condition of the entire economy, and is linked to the capital spending under the Customer Growth – New Extensions Program. Using Alberta GDP also avoids some of the volatility associated with using the price of oil as a forecasting input.[306]

301 Exhibit 26615-X0023, ATCO Electric application, Appendix I.4, PDF page 322.
302 Exhibit 26615-X0023, ATCO Electric application, Appendix I.4, PDF page 326.
303 Exhibit 26615-X0023, ATCO Electric application, Appendix I.4, PDF page 324.
304 Exhibit 26615-X0023, ATCO Electric application, Appendix I.4, PDF page 324.
305 Exhibit 26615-X0023, ATCO Electric application, Appendix I.4, PDF pages 324-325.
306 Exhibit 26615-X0023, ATCO Electric application, Appendix I.4, PDF pages 325-326.

321. To forecast capital additions for this program, ATCO Electric started by calculating the average of 2018-2020 capital additions for small new extensions and large new extensions, escalated by customer growth and inflated to 2020 dollars,[307] using actual inflation experienced in each calendar year. Then, to index the 2018-2020 average to 2023, ATCO Electric adjusted for inflation in each of 2021, 2022 and 2023, and lastly adjusted for customer growth using the average of "All GDP," which was determined by taking an average of forecasts developed by the Government of Alberta, the Conference Board of Canada and financial institutions.[308]

Table 18. Customer Growth – New Extensions Alternative Forecasting Comparison

	Applied-for forecast				Alternative 1 forecast				Alternative 2 Mechanistic escalated three-year average (2018-2020)
	Methodology	Forecast ($ million)			Methodology	Forecast ($ million)			Forecast ($ million)
Small new extensions		**2021**	**2022**	**2023**		**2021**	**2022**	**2023**	
Residential/commercial/ farm extensions	Average of all GDPs	29.6	31.6	33.4	Average housing starts	27.4	31.4	36.5	
Oilfield/industrial extensions	Average of all GDPs	40.5	43.3	45.7	WCS @Hardisty	42.0	54.6	57.1	
Street and sentinel lights	Average of all GDPs	4.2	4.5	4.7	Average housing starts	3.9	4.5	5.2	
Subtotal small new extensions		74.3	79.4	83.8		73.3	90.5	98.8	
Large new extensions	Average of all GDPs	30.8	32.9	34.8	WCS @Hardisty	31.9	41.5	43.4	
Total		105.1	112.3	118.6		105.2	132.0	142.2	105.5

Source: Exhibit 26615-X0177, AE-AUC-2022JAN14-019(a), Table 1.

322. The Commission has reviewed the forecast methodology proposed by ATCO Electric and the different alternatives provided on the record of this proceeding (as outlined in Table 18 above). Based on that review, the Commission finds ATCO Electric's proposed forecasting methodology to be reasonable. Using Alberta GDP as the principal driver of customer growth for ATCO Electric is reasonable given the observed relationship between this indicator and ATCO Electric's new customer extensions. Moreover, using Alberta GDP mitigates some of the volatility in ATCO Electric's forecasts attributable to the price of oil and solves for changes in how housing starts data is published by Canada Mortgage and Housing Corporation.

323. The Commission approves capital additions of $118.6 million, subject to adjusting the forecast for this program by using the escalation factors approved in Section 5.2.

324. Given that ATCO Electric's unit costs for the Customer Growth - New Extensions program are based on current maximum investment level rates, the Commission recognizes that the forecast may need to be revised if any changes are made to maximum investment levels

307 Exhibit 26615-X0024, Appendix A, Sch 4.1b, Excel line 15.
308 Exhibit 26615-X0023, ATCO Electric application, Appendix I.4, PDF page 327.

through the consultation process outlined in Bulletin 2022-07. As discussed in Section 8.2.1 for Fortis above, the Commission may issue further direction to ATCO Electric on how to incorporate any changes to maximum investment levels at the conclusion of the consultation process.[309]

8.3.2.2 Wildfire Mitigation

325. To address the risks of wildfires, ATCO Electric forecast capital additions for 2023 above the escalated 2018-2020 average for its Forestry Protection and Overhead Line Rebuilds, Replacements and Life Extensions programs. ATCO Electric explained that these two programs complement each other. Both programs have similar drivers to combat the risk of wildfires, but use different approaches to address that risk. Forestry Protection uses a vegetation management-focused approach. Overhead Line Rebuilds, Replacements and Life Extensions uses an asset-focused approach.[310]

326. In this section, the Commission first addresses the Forestry Protection Program, followed by the Overhead Line Rebuilds, Replacements and Life Extensions Program.

8.3.2.2.1 Forestry Protection

327. The Forestry Protection Program, also referred to by ATCO Electric as the Wildfire Risk Reduction Program or the Wildfires Mitigation Program (WMP) is required to minimize the occurrence and severity of powerline-caused wildfires and to comply with ATCO Electric's obligations in the Forest Protection Area (FPA). These obligations are outlined in a Wildfire Agreement with Alberta Agriculture and Forestry (AAF) and an Electric Distribution Agreement with Parks Canada.[311]

328. The WMP comprises five activities, as shown in the table below.

Table 19. Wildfires Mitigation Program forecast capital additions

	2023F	2018-2020 escalated average	Variance between forecast and average
Activity	Capital additions ($000)		
Clearance and Safety (removal of previously trimmed trees to reduce future need to trim these trees again)	7,159	7,159	0
Hazard Tree (removal of a single or small number of trees where there is a high-risk that trees will topple over and contact powerlines)	10,732	9,204	1,528
Tree-Free (removal of all trees that have the potential to topple over and make contact with a powerline, usually located in remote areas and serve high customer loads)	5,959	4,852	1,107
FireSmart (removal of vegetation along powerlines to protect communities from the threat of powerline-related wildfires)	1,135	2,003	(868)
Total capital additions related to tree removal	**24,985**	**23,218**	**1,767**

309 Bulletin 2022-07, PDF pages 1-2.
310 Exhibit 26615-X0023, ATCO Electric application, Appendix I.1 Wildfire Risk Reduction Program Business Case, PDF page 201.
311 Exhibit 26615-X0023, ATCO Electric application, PDF page 45, Table 13.

	2023F	2018-2020 escalated average	Variance between forecast and average
Activity	**Capital additions ($000)**		
LiDAR Acquisition & Analysis (the acquisition of vegetation inventory along Right of Ways)	4,399	1,412	2,987
Total capital additions	**29,383**	**24,630**	**4,754**

Source: Exhibit 26615-X0023, ATCO Electric application, PDF page 151, Table 6, and Appendix I.1 Wildfire Risk Reduction Program Business Case, PDF page 227, Table 1; Exhibit 26615-X0177, AE-AUC-2022JAN14-008(a) and (d).

Tree removal activities

329. The first four activities listed in Table 19 above relate to tree removal. ATCO Electric forecast the clearance and safety activity mechanistically using the escalated 2018-2020 average capital additions. The 2023 forecast for the remaining activities is based on assessments by ATCO Electric forestry professionals who determined the work that would be required to address the increasing risks of wildfire observed in Alberta. ATCO Electric explained that due to these risks, an increase in capital additions over historical averages is required.[312]

330. The CCA and the UCA opposed the capital additions in excess of the three-year average of historical costs. They argued that they were unable to assess the reasonableness of the wildfire mitigation plans because ATCO Electric had not demonstrated the effect of the plans on risk reduction or how trends and historical events across Alberta applied to ATCO Electric's distribution system.[313] ATCO Electric explained that it has legal obligations to address wildfire risk and its plans are developed with AAF. ATCO Electric rejected intervener claims that its plans are not specific to ATCO Electric's distribution system, as it uses the risk assessments conducted for ATCO Electric by Forsite.[314]

331. For the reasons that follow, the Commission finds the forecast WMP capital additions of $29.383 million to be reasonable, and approves them, subject to adjusting the forecast for this program using the escalation factors approved in Section 5.2.

332. The Commission finds that an additional $1.767 million in capital additions for tree removal work is reasonable because:

(a) Vegetation management as a means to address wildfire risk was supported by the CCA's expert witness. Dr. Don Russell confirmed that vegetation management should be one of the primary tools employed by a utility when it comes to wildfire mitigation.[315]

(b) Wildfire risk is increasing. ATCO Electric provided graphs in its application showing that trends in area burned, powerline-related wildfires and tree contact

312 Exhibit 26615-X0023, ATCO Electric application, Appendix I.1 Wildfire Risk Reduction Program Business Case, PDF pages 226-227.

313 Transcript, Volume 5, page 746, line 23 to page 747, line 10 (CCA argument, J. Wachowich); page 797, lines 14-20; page 802, lines 3-5 (UCA argument, K. Rutherford).

314 Transcript, Volume 6, page 871, lines 15-20 (ATCO Electric reply argument, L. Smith).

315 Transcript, Volume 1, page 16, lines 2-5.

with powerlines resulting in wildfires are increasing.[316] The Commission accepts the evidence supporting ATCO Electric's position that wildfire risk is growing and, therefore, that additional work is required to mitigate the increasing risk.

(c) ATCO Electric's forecast capital additions were supported by a report developed by Forsite, a recognised wildfire expert that has Alberta-specific experience. Forsite prepared a report for ATCO Electric that assisted the utility to develop its wildfire mitigation plans. In Decision 26509-D01-2022 (Corrigenda), the Commission considered Forsite to have specific expertise in the field of wildfire behaviour modelling including specialized knowledge, training, skills and experience. The Commission still considers that to be the case.[317]

LiDAR acquisition and analysis

333. ATCO Electric proposed the Light Detection and Ranging (LiDAR) Project, in the amount of $4.399 million for 2023, to increase efficiency in completing ground-based patrols and for the purposes of optimization modelling and risk-based vegetation management. Topographic features such as watercourses and steep slopes can also be captured by LiDAR.[318] ATCO Electric considered LiDAR data to be superior to traditional ground patrols. ATCO Electric indicated that the implementation of LiDAR would reduce the required effort of ground patrols, but would not eliminate the need for ground patrols because LiDAR does not obtain all the data required to identify potential hazard tree locations.[319] When asked by the Commission if ATCO Electric expects the use of LiDAR will result in decreased expenditures in widening and hazard tree programs, ATCO Electric stated that the use of LiDAR is unlikely to decrease overall expenditures in the vegetation management programs.[320] When asked by the Commission if any operational savings are expected to be realized as a result of the implementation of LiDAR, ATCO Electric stated that it anticipated expenditures for ground patrols to decline somewhat.[321] The CCA and the UCA opposed the total capital additions for the WMP that were in excess of the three-year escalated average, in the amount of $4.754 million.

334. The interveners did not file evidence either in support of or in opposition to ATCO Electric's LiDAR project. Bema, on behalf of the CCA, mentioned LiDAR as an example of a technology that could be adopted in a WMP vegetation management program.[322] In the oral hearing, the Commission asked Dr. Russell about his knowledge and experience with the efficacy of LiDAR in advanced vegetation management. He noted that he is very familiar with the technology, that LiDAR provides extremely valuable information and it is a "great technology." Dr. Russell has extensive experience with LiDAR as a forensic tool to determine

---

316 Exhibit 26615-X0023, ATCO Electric application, Appendix I.1 Wildfire Risk Reduction Program Business Case, PDF page 206, Figure 3: Hectares Burned in Alberta 1990-2021; PDF page 215, Figure 8: Powerline-related Wildfires in Alberta 1990-2020; PDF page 217, Figure 10: Tree Contact with Powerlines Resulting in Wildfires in ATCO Electric Service Area.
317 Decision 26509-D01-2022 (Corrigenda), paragraph 436.
318 Exhibit 26615-X0023, ATCO Electric application, Appendix I.1 Wildfire Risk Reduction Program Business Case, PDF page 226.
319 Exhibit 26615-X0177, AE-AUC-2022JAN14-009(d)-(f).
320 Exhibit 26615-X0177, AE-AUC-2022JAN14-009(d).
321 Exhibit 26615-X0177, AE-AUC-2022JAN14-009(e-f).
322 Exhibit 26615-X0310.02, CCA evidence of Bema, paragraph 47.

the cause of fires after they occur. He stated that he did not have the expertise to comment on the benefits of its use in reducing wildfire risk as compared to other means.[323]

335. The Commission observes that approximately one third of the $4.754 million variance between the 2023 forecast and the escalated 2018-2020 average is attributable to tree removal, and the remaining two-thirds to the LiDAR project. Given limited intervener evidence filed in respect of the LiDAR project, which contributes a significant portion of the costs of capital additions in excess of the three-year average, the Commission is not persuaded by the opposition of the CCA and the UCA to the approval of any capital additions above the three-year escalated average.

336. The Commission acknowledges the value of LiDAR technology as indicated by ATCO Electric and interveners. For example, in Decision 23848-D01-2020,[324] the Commission approved AltaLink's system-wide, one-effort approach to LiDAR surveying to mitigate line clearance deficiencies across all of its 13,385 km of transmission system.[325] Therefore, the Commission approves capital additions of $4.399 million as forecast for the LiDAR project for 2023. However, the Commission does not accept ATCO Electric's statement that the use of LiDAR is unlikely to decrease expenditures in the future. The Commission expects that ATCO Electric's investment in this technology would allow it to find opportunities to reduce costs, given that, as claimed by ATCO Electric, LiDAR will optimize modelling and risk-based vegetation management.

337. The CCA and the UCA submitted that ATCO Electric's WMP was not supported by ATCO Electric system specific data and quantifiable measures to determine the cost-effectiveness of the mitigation measures adopted.[326] The Commission agrees that ATCO Electric's evidence in this proceeding neither demonstrates that it evaluates the performance of its WMP, nor that it collects data when a wildfire does occur.[327] Therefore, the Commission directs ATCO Electric to provide, in the compliance filing, a cost-effective proposal to monitor the progress of its WMP and measure the effectiveness of the related capital expenditures. The proposal should include processes and procedures required to (i) track and report all details relating to wildfire incidents; (ii) identify the measures to be implemented to resolve the incidents; and (iii) assess the effectiveness of those measures in mitigating the incidents.

8.3.2.2.2 Line Rebuilds, Replacements and Life Extensions

338. The Line Rebuilds, Replacements and Life Extensions Program is required to maximize the life of ATCO Electric's overhead powerline and underground cable assets by rebuilding, replacing or extending the life of these assets. ATCO Electric used a hybrid approach in forecasting its 2023 capital additions for this program. A portion of the program, which includes

---

323 Transcript, Volume 1, page 44, line 12 to page 46, line 24.

324 Decision 23848-D01-2020: AltaLink Management Ltd., 2019-2021 General Tariff Application Negotiated Settlement Agreement and Excluded Matters, Proceeding 23848, April 16, 2020.

325 Decision 23848-D01-2020, paragraphs 201 and 239.

326 Transcript, Volume 5, page 756, lines 17-25 (CCA argument, J. Wachowich); Transcript, Volume 5, page 797, line 7 to page 799, line 4 (UCA argument, K. Rutherford).

327 For example, when asked by the CCA to provide fire investigation reports for all powerline-caused wildfires on its system for the last 10 years and specifically include fire cause and origin reports and root cause findings, ATCO Electric replied that it was not able. See Exhibit 26615-X0233, AE-CCA-2022JAN21-033(a).

wood pole replacements and life extensions, and underground rebuilds, replacements and life extensions, was forecast mechanistically using the escalated 2018-2020 average of capital additions. ATCO Electric submitted that for the remaining portion of the program, an increase in capital additions over historical averages is required due to the increased risk of wildfires.[328]

339. The Line Rebuilds, Replacements and Life Extensions Program 2023 forecast is set out in the table below.

Table 20. Line Rebuilds, Replacements and Life Extensions Program forecast capital additions

Description	2023 Forecast ($000)	2018-2020 Escalated Average ($000)	Variance between forecast and average
Line Rebuilds, Replacements and Life Extensions – Mechanistic*	26,683	26,683	0
Overhead Line Rebuilds, Replacements and Life Extensions (non-mechanistic)**	21,299	12,381	72%
Total Rebuilds, Replacements and Life Extensions	**47,982**	**39,065**	**23%**

Source: Exhibit 26615-X0023, ATCO Electric application, PDF page 149, Table 5.
*The mechanistic approach was used for wood pole replacements and life extensions and underground rebuilds, replacements, and life extensions.
**The non-mechanistic approach was used for overhead line and conductor rebuilds, transformer and equipment replacements, streetlight replacements and life extensions, ground rod replacements and insulator and switch replacements, which ATCO Electric refers to as the Overhead Line Rebuilds, Replacements and Life Extensions program.

340. The CCA was opposed to the increase over the escalated 2018-2020 average. In its view, the increase was unsupported, as ATCO Electric did not adequately show how it scopes and estimates wildfire mitigation work. Further, quantified measures of the work, the location of the work and the risk reduction to be achieved were not provided.[329]

341. To gain a better understanding of the forecast costs, the Commission, in an IR, asked ATCO Electric to provide more support for its requested capital additions over the escalated 2018-2020 average. ATCO Electric explained that, first, the entire program was forecast mechanistically to determine if the result produced an appropriate or reasonable forecast for 2023. If not, it further evaluated the subprograms to determine which subprogram required a non-mechanistic forecast. ATCO Electric identified the Overhead Line Rebuilds, Replacements and Life Extensions subprogram as requiring a non-mechanistic forecast.

342. The Commission finds this response to be inadequate. In particular, ATCO Electric has not explained what led it to conclude that a mechanistic forecast for the entire program did not produce "an appropriate or reasonable forecast for 2023," and it has not sufficiently supported the need for the amount it forecast over the 2018-2020 escalated average. ATCO Electric reiterated the need to address the increasing wildfire risk in Jasper National Park and the FPA, and noted that many of the assets evaluated are also approaching their end of life. The evaluation resulted in an increase in overhead line rebuilds, replacement and life extension capital work in

328 Exhibit 26615-X0023, ATCO Electric application, PDF pages 149-150.
329 Transcript, Volume 5, page 746, line 12 to page 747, line 10 (CCA argument, J. Wachowich).

2023, "which is necessary to maintain the safe, reliable delivery of electricity to its customers."[330] The Commission understands that ATCO Electric needs to maintain safe and reliable service; however, it is not persuaded that such a statement on its own justifies the need for additional funds. The Commission also notes that a substantial increase to this program is being sought for the rebasing year of the next PBR period. Without evidence to the contrary, the Commission finds that total rebuilds, replacements and life extensions due to aging assets and wildfire risk in ATCO Electric's service area as a whole could be prioritized within the budget provided by the escalated 2018-2020 average. Therefore, the Commission agrees with the CCA that the evidence provided by ATCO Electric was insufficient to establish the need for the incremental capital additions it requested. It is not clear to the Commission how the additional work as planned in the timeframe proposed will impact wildfire risk.

343. When asked to provide details, for example, regarding the number of kilometres of line and locations, of the work forecast for 2023, ATCO Electric explained that details are not available until detailed plans are developed and the projects are prioritized on an annual basis.[331] While the Commission finds this response to be sensible, it is unclear to the Commission how ATCO Electric was able to determine that it needed funding incremental to that provided by the three-year escalated average without detailed plans and project prioritization.

344. The table below shows a comparison of ATCO Electric's 2021 actual and 2021 forecast capital additions for the Rebuilds, Replacements and Life Extensions Program.[332]

Table 21. Line Rebuilds, Replacements and Life Extensions 2021 actual capital additions

Description	2021 Preliminary actual	2021 Forecast	Variance	Variance
	($000)			(%)
Mechanistic (Escalated 3-Year Average)	19,263	25,271	(6,008)	(24)
Overhead Line Rebuilds, Replacements and Life Extensions (non-mechanistic)	11,678	17,472	(5,794)	(33)
Total Rebuilds, Replacements and Life Extensions	**30,942**	**42,743**	**(11,801)**	**(28)**

345. ATCO Electric explained that the $11.8 million variance was largely attributable to supply chain challenges.[333] During questioning by the Commission in the hearing, Gurb Hari stated that ATCO Electric expects supply chain issues will continue into 2023, but does not foresee experiencing the same issue in 2023 at the same level as indicated by the variance in 2021. He explained that ATCO Electric is actively addressing the issue by ordering materials early and building up inventory levels.[334]

330 Exhibit 26615-X0177, AE-AUC-2022JAN14-013(d).
331 Exhibit 26615-X0177, AE-AUC-2022JAN14-013(c).
332 Exhibit 26615-X0412, paragraph 59, Table 13.
333 Exhibit 26615-X0412, paragraph 60.
334 Transcript, Volume 3, page 395, line 14 to page 397, line 4.

346. Considering the supply chain issues and upward pressures on cost, the Commission asked ATCO Electric if it was possible to defer work scheduled for this program. G. Hari emphasized that the work planned for 2023 to mitigate wildfire risk cannot be deferred. However, he noted that age and condition also play a factor in prioritizing projects. He explained that ATCO Electric identifies those projects that are of highest risk, and completes those first, regardless of the year in which they were originally planned.[335]

347. The Commission is not persuaded that the additional costs requested for 2023 cannot be deferred. ATCO Electric spent 28 per cent less than forecast in 2021 yet was able to manage the impacts of underspending by reassessing the original schedule and reprioritizing its projects in 2022. To be clear, the Commission is not suggesting that projects should be deferred indefinitely, nor is the Commission basing the reasonableness of ATCO Electric's 2023 forecast on ATCO Electric's past forecasting record. The Commission recognizes the need for the Line Rebuilds, Replacements and Life Extensions Program. However, the Commission is of the view that the projects in this program could be prioritized based on the various factors that carry the most risk overall (e.g., age and condition of the assets, wildfire risk), without the need for additional capital additions in excess of the three-year escalated average.

348. Further, as testified by Dr. Russell, there is a low probability of an ignition event on any one powerline as "[w]e operate, you know, millions of miles of power lines all year long with a very small number of events that are ignition competent to cause a wildfire."[336] Therefore, the Commission is not persuaded that accelerating the rebuilding of lines, at significant capital cost, is the most reasonable course of action to reduce wildfires.

349. The Commission understands that ATCO Electric has assessed wildfire risk by identifying the most likely locations based on environmental factors, and by considering, if a fire does occur, where it will have the most impact. The Commission agrees with the CCA that this "is like doing half a job."[337] To complete the analysis, the Commission finds that identification of which components of a distribution system are likely to cause an ignition, as suggested by Dr. Russell in his evidence,[338] has merit. In the hearing, Dr. Russell explained that investments in equipment and technology have many benefits to potentially assist in wildfire ignition prevention, as well as assisting to improve reliability on a regular basis. He described such installations as a "no-brainer."[339] Therefore, without endorsing any specific equipment or technology, the Commission finds that it would be prudent for ATCO Electric to consider equipment and technology to assist it in its decisions regarding the identification of specific projects to be completed in its Line Rebuilds, Replacements and Life Extensions Program. The Grid Modernization Program, which the Commission has approved in Section 8.3.2.4, could facilitate the use of equipment and technology to identify components of ATCO Electric's distribution system that are more likely to cause an ignition and that, therefore, could assist in wildfire ignition prevention.

335 Transcript, Volume 3, page 400, line 2 to page 403, line 24.
336 Transcript, Volume 1, page 26, lines 15-22.
337 Transcript, Volume 5, page 748, lines 3-7 (CCA argument, J. Wachowich).
338 Exhibit 26615-X0332, CCA evidence of B.D. Russell and C. Benner, paragraph 33, for example.
339 Transcript, Volume 1, page 18, line 16 to page 20, line 22.

350. For these reasons, the Commission denies ATCO Electric's 2023 forecast capital additions for the Line Rebuilds, Replacements and Life Extensions Program that are above the escalated 2018-2020 average. Therefore, the Commission approves capital additions of $39.065 million, subject to adjustments resulting from using the escalation factors approved in Section 5.2, and directs ATCO Electric to remove the additional forecast costs above this amount from this program in its compliance filing.

8.3.2.3 General Support

351. The General Support Program is for capital investments to support ongoing operations including vehicles, work equipment, tools, upgrades and improvements to land and structures, communication equipment, computer hardware and software. ATCO Electric used a hybrid approach in forecasting its 2023 capital additions for this program. Most of the subprograms were forecast mechanistically using the escalated 2018-2020 average of capital additions. One subprogram, Transportation Equipment, which comprises 42 per cent of the total forecast capital additions for this program, was forecast using a bottom-up approach.

352. The 2023 forecast capital additions for the General Support Program are set out in the table below.

Table 22. General Support Program forecast capital additions

Description	2023 forecast	2018-2020 escalated average
	($000)	
Buildings, Structures & Leasehold Improvements	4,173	4,173
Communications Structures & Equipment	490	490
Tools & Instruments	1,791	1,791
Information Technology Related	15,024	15,024
Total mechanistic forecast	**21,478**	**21,478**
Transportation Equipment (non-mechanistic)	15,650	6,595
Total General Support	**37,128**	**28,073**

Source: Exhibit 26615-X0180, AE-AUC-2022JAN14-015(a)-(b) Attachment 1.

353. The Commission finds that the subprograms that were forecast using the mechanistic approach are reasonable and approves the forecast capital additions as filed in the amount of $21.478 million, subject to adjustments resulting from using the escalation factors approved in Section 5.2.

354. Transportation equipment is replaced by ATCO Electric as each asset reaches the end of its useful life. Using a vehicle health index tool, ATCO Electric determined its 2023 forecast capital additions that are required to meet its needs. Ongoing challenges in the procurement of vehicles beginning in 2021 due to supply chain issues increased the number of end-of-life assets as well as capital repair costs.[340] The following table identifies the transportation equipment types that are forecast by ATCO Electric to be replaced in 2023.

[340] Exhibit 26615-X0023, ATCO Electric application, Appendix I.3 - Transportation Equipment, PDF page 310.

Table 23. 2023 Forecast fleet replacements[341]

Equipment type	Total beginning of 2023	Replacements	Total ($000)
ATV	45	0	0
Light/Medium	388	63	6,350
Trailers	195	16	1,300
Backhoes/Skidsteers	24	3	300
Radial Boom Diggers	59	5	2,900
Insulated Manlifts	72	5	2,600
Crane Trucks	5	1	450
Forklifts	24	3	250
Large Off-road Equipment	11	1	1,200
Capital Repairs & Mounted Equipment Refurb			300
Total	**823**	**97**	**15,650**

355. The Commission accepts ATCO Electric's reasons for the need for additional funds over the 2018-2020 escalated average. However, and for the reasons that follow, the Commission finds that $15,650 million in forecast expenditures for 2023 is excessive, and denies 50 per cent of the capital additions in excess of the escalated 2018-2020 average.

356. First, ATCO Electric did not perform any analysis to verify that any reduction in capital additions would increase asset total cost of ownership.

357. ATCO Electric disagreed with any suggestion that its 2023 capital forecast for transportation equipment could be reduced. It explained that any reduction would increase asset total cost of ownership by driving up maintenance costs on old assets, reducing service reliability and operational efficiency.[342] G. Hari confirmed that fleet operating and maintenance costs have increased by 24 per cent over the last three years as more vehicles come to their end of life and become more expensive to maintain.[343] When asked if an analysis was done to assess whether it could be beneficial to defer some of ATCO Electric's fleet additions, particularly in view of the current increasing price environment, G. Hari replied that ATCO Electric did no such analysis.[344] Accordingly, in the Commission's view there was no evidence on the record of this proceeding that showed that procuring all vehicles forecast by ATCO Electric, would minimize net present value of revenue requirement (i.e., maximize benefits at the lowest total cost to customers), in the current constrained supply, and therefore higher price environment.

358. Second, the Commission does not accept that the purchase of certain vehicles and equipment scheduled for replacement in 2023 cannot be deferred. The Commission considers ATCO Electric to have the skills, experience and ability to prudently manage its fleet within the amounts approved without affecting its service quality and reliability. Melanie Bayley, ATCO

341 Exhibit 26615-X0023, ATCO Electric application, Appendix I.3.A - Transportation Equipment, PDF page 319, Table A1.
342 Exhibit 26615-X0177, AE-AUC-2022JAN14-017(b).
343 Transcript, Volume 3, page 426, lines 10-14.
344 Transcript, Volume 3, page 429, line 16 to page 430, line 8.

Electric's President, stated that capital can be deferred for a short period of time and that ATCO Electric has moved to risk-based and condition-based approaches, rather than the traditional cyclical procurement approach. M. Bayley noted that considering the current inflation impact, ATCO Electric is being careful with its deployment of capital.[345] In the Commission's view, the equipment types shown in Table 23 are sufficiently diverse, with a large number being of a non-specialized nature, such as light and medium trucks, which based on M. Bayley's testimony could be considered for life extensions.

359. Third, given the evidence of ongoing supply chain disruptions and continued supply-side constraints in the transportation equipment market, as described below, the Commission is not confident that ATCO Electric will spend its total proposed forecast in 2023.

360. The table below shows a comparison of ATCO Electric's 2021 actual and 2021 forecast capital additions for the General Support Program.[346]

Table 24. General Support 2021 actual capital additions

Description	2021 Preliminary actual	2021 Forecast	Variance	Variance
	($000)			(%)
Mechanistic (Escalated 3-Year Average)	25,563	20,342	5,221	26
Transportation Equipment	5,540	9,300	(3,760)	(40)
General Support	**31,103**	**29,642**	**1,461**	**5**

361. ATCO Electric underspent its 2021 forecast capital additions in transportation equipment costs by 40 per cent. ATCO Electric explained that this variance between 2021 actuals and its 2021 forecast was largely attributable to supply chain challenges.[347] During questioning in the hearing, ATCO Electric's witness, G. Hari, stated that although he expects supply chain issues to continue, ATCO Electric is mitigating supply chain challenges by ordering vehicles earlier than usual. This strategy resulted in ATCO Electric receiving all required vehicles for 2021 by Q1 of 2022 and half of the required vehicles for 2022 had been received at the time of the oral hearing, with the remainder expected in July of 2022. Similar to the procurement strategy of 2022, orders for vehicles identified for 2023 will begin in July 2022.[348]

362. The supply chain issues experienced in 2021 and 2022 and that also caused ATCO Electric to significantly underspend its 2021 forecast capital additions for this program are expected to continue. While the Commission acknowledges ATCO Electric's efforts to mitigate supply chain issues, the Commission anticipates that these issues will continue into 2023. When asked whether ATCO Electric expects the supply chain issue to abate, G. Hari expressed some doubt that it will.[349] The significant variance between 2021 actuals and 2021 forecast in transportation equipment capital additions indicates that supply chain issues can have a considerable effect on ATCO Electric's ability to spend funds to meet its target capital additions.

345 Transcript, Volume 3, page 390, lines 9-25.
346 Exhibit 26615-X0412, paragraph 64, Table 14.
347 Exhibit 26615-X0412, paragraph 65.
348 Transcript, Volume 3, page 420, lines 3-21.
349 Transcript, Volume 4, page 583, line 12 to page 584, line 1.

The Commission is therefore not persuaded that ATCO Electric will be able to spend the amounts it has forecast for 2023 for transportation equipment.

363. Based on the foregoing, the Commission approves 2023 forecast capital additions of $11.122 million for the Transportation Equipment Program, and directs ATCO Electric to remove $4.527 million in capital additions for this program in its compliance filing.

8.3.2.4 Grid Modernization

364. ATCO Electric proposed a new capital Grid Modernization Program (GMP), to ensure its distribution system can accommodate a fundamental shift in grid usage that will be brought about by a rise in DERs and EVs, decarbonization efforts, changing customer expectations and behaviors, and a changing and challenging climate.[350]

365. ATCO Electric provided a roadmap of the GMP, which showed planned implementations and outcomes for the 2023-2028 period.[351] The GMP comprises three categories of projects, as identified in the table below, and proposed capital additions of $39.1 million for 2023.

Table 25. Grid Modernization Program 2023 forecast capital additions

Description	2023 capital additions ($ million)
Advanced Distribution Management System (ADMS) & Technology Projects: development of six foundational applications that will utilize information received from AMI and SCADA, consisting of (1) switch order management, (2) short circuit analysis, (3) feeder reconfiguration, (4) fault location, isolation, and service restoration, (5) restoration switching and (6) distribution analytics.	5.9
Asset Modernization Projects: add DSCADA capability to 350 devices (protective devices such as reclosers, switching points such as gang switches or switching cubicles, and voltage control devices such as voltage regulators).	19.6
Advanced Metering Infrastructure (AMI) projects: deployment of 48,000 meters across 10 service points.	13.6
Total	**39.1**

Source: Exhibit 26615-X0023, ATCO Electric application, Appendix I.5 Grid Modernization Business Case, PDF pages 347-348, Table 3.

366. ATCO Electric explained how the three categories of projects, working in conjunction with one another, will support the operational requirements of a more complex grid.[352]

- AMI will collect grid data such as real-time outage and energy usage data, offering benefits including:
  - (i) enhanced customer information and control over electricity consumption to allow for integration and management of DERs;
  - (ii) dynamic planning models for improved system monitoring and analysis;

[350] Exhibit 26615-X0023, ATCO Electric application, Appendix I.5 Grid Modernization Business Case, PDF pages 331-354.
[351] Exhibit 26615-X0023, ATCO Electric application, Appendix I.5 Grid Modernization Business Case, PDF page 346, Table 2.
[352] Exhibit 26615-X0023, ATCO Electric application, Appendix I.5 Grid Modernization Business Case, PDF pages 342-345.

(iii) enabling dynamic rates such as time of use; and

(iv) the ability to remotely connect or disconnect a customer.

- Asset modernization projects will provide data and remote visibility and control at key devices, the ability to identify the location of system issues and the ability to then remotely reconfigure the system to address these issues.

- ADMS will provide a foundation that enables other operational functions and advanced capabilities and uses information received from AMI and SCADA devices. It will provide system operators with operational intelligence about the current state of the grid, which helps to maintain system reliability, reduces field personnel hazards, improves wildfire safety, and helps in monitoring DERs on the system and the challenges posed by growing EV loads.

367. ATCO Electric noted that it had applied for grant funding in the 2022-2024 period through Natural Resource Canada's (NRCan) Sustainable Resource Electrification Pathways (SREP) Program. In the hearing, Matt Sveinbjornson confirmed that ATCO Electric had secured funding of 50 per cent of its expenditures for the ADMS project and that applications for the remaining two projects (i.e., AMI and Asset modernization projects) are in progress. As he understands, these applications meet NRCan's funding criteria for the program and funds of up to 50 per cent, to a maximum of $50 million per project, are available from Q1 of 2022 to the end of Q1 2025. He noted that ATCO Electric will update its forecast 2023 revenue requirement in the compliance filing to reflect the approval of the NRCan grant for its ADMS project.[353]

368. The UCA recommended that all of the GMP 2023 forecast capital additions proposed by ATCO Electric be denied. The UCA was concerned that the business case did not quantify any specific savings and did not present any reasonable alternatives. The UCA questioned ATCO Electric's motives for waiting until 2022[354] to make significant investments in the program, rather than starting earlier in the 2018-2022 PBR term. In its view, the uncertainty around the adoption of EVs and the slowing pace of DER installations in ATCO Electric's service area do not support the proposed pace of the GMP.[355]

369. ATCO Electric dismissed the UCA's concerns. It explained that the GMP is not driven by a quantitative comparison of alternatives. The program is driven by global trends that will require ATCO Electric to change the way it operates its distribution system.[356] The implementation of technologies as set out in the GMP is required to address the transformative changes in how customers will use the grid in the future. ATCO Electric explained that it has planned and is implementing the GMP in a staged manner based on the results of small asset modernization and AMI pilots implemented in the 2018-2020 timeframe, and due to the time

353 Exhibit 26615-X0414, ATCO Electric rebuttal evidence, paragraphs 132-133; Transcript, Volume 3, page 495, lines 12-24, and page 496, line 16 to page 497, line 21.

354 Exhibit 26615-X0023, ATCO Electric application, PDF page 54, Table 15 shows 2022 forecast capital additions of $27.9 million.

355 Exhibit 26615-X0476, UCA argument, paragraphs 63-71.

356 Exhibit 26615-X0177, AE-AUC-2022JAN14-022(d).

required to implement the required technology across its service area, it must take a responsible proactive approach to grid modernization.[357]

370. The Commission accepts ATCO Electric's explanation that a quantitative comparison of alternatives for the GMP may not be feasible at this time. The Commission is aware of government policy announcements and the potential for an increased number of DERs and EVs that will connect with and impact the operation of electrical distribution systems. The DSI findings support the need for grid modernization to address changes in the way the electrical distribution system is used. The grant funding that is potentially available from NRCan for grid modernization projects is a further indication that the need to begin investing in large-scale, innovative grid modernization initiatives is increasingly well recognized and supported by various levels of government.

371. ATCO Electric stated that it started evaluating and planning grid modernization from 2017 to 2019. It installed AMI meters in Grande Prairie and Fort Chipewyan on a pilot basis.[358] ATCO Electric started spending in this program in 2020 with capital additions of $0.685 million, followed by forecast capital additions of $6.878 million and $27.915 million in 2021 and 2022, respectively.[359] In this application, ATCO Electric presented a road map, which included its plans from 2023 to 2028 related to the three interconnected projects in its GMP. In consideration of the observations in the DSI, released in February 2021, the current uncertainty with respect to the pace of DERs and EV adoption in ATCO Electric's service area and the timing of the availability of the NRCan funding, the Commission finds ATCO Electric's cautious approach with relatively little spending in the 2017-2021 time period, followed by a staged implementation of ADMS projects, AMI meters and Asset Modernization projects in the 2022-2028 time period, to be reasonable.

372. The Commission therefore finds ATCO Electric's GMP to be reasonable and approves the 2023 forecast capital additions, subject to adjustments to reflect the approval of the NRCan grant for the ADMS project and any other subsequent grants received from NRCan for the Asset Modernization and AMI projects.

373. To reflect the grant funding that ATCO Electric has secured for the ADMS project, the Commission directs ATCO Electric to remove 50 per cent of its 2023 forecast costs in the amount of $2.95 million for this project in its compliance filing. The Commission also directs ATCO Electric to provide the status of its NRCan grant applications for the AMI and Asset Modernization projects including any early information it may have on whether it is likely to secure the grants. If one or more of the grant applications are approved, ATCO Electric is directed to remove the amount of any grant funding amounts from its 2023 forecast costs for the relevant projects in the compliance filing. If the status of the grant application is not available at the time of the compliance filing, the Commission will consider whether any adjustments are

[357] Exhibit 26615-X0177, AE-AUC-2022JAN14-022(b).
[358] Exhibit 26615-X0414, ATCO Electric rebuttal evidence, paragraphs 122-123.
[359] Exhibit 26615-X0024, ATCO Electric application, Appendix A - ATCO Electric Commission Template, Sch 4.1, line 14.

required to ATCO Electric's forecasts for these projects based on the information provided at the time of the compliance filing.

Depreciation rates for meters

374. If ATCO Electric implements its GMP as expected and replaces all of its automatic meter reading (AMR) meters with AMI meters, the service lives of AMR meters are expected to change. ATCO Electric's proposed change to depreciation rates would result in a $1.4 million increase to its annual depreciation expense in ATCO Electric's applied-for 2023 revenue requirement.[360]

375. ATCO Electric recognized that depreciation studies and technical updates were outside of the scope of this 2023 COS proceeding; however, it stated the proposed depreciation adjustment did not fall within a full depreciation study or technical update because no changes have been made to the relevant approved Iowa Curve. ATCO Electric sought a final approval of its depreciation proposal in conjunction with the proposed pace of its AMR meter replacements. It noted that there is a correlation between the expected service lives of the assets and drivers impacting the expected service life. While the Commission considers that a strict interpretation of its direction[361] precludes *any* changes to the previously approved depreciation parameters, the Commission is prepared to consider ATCO Electric's request in this proceeding, given its limited nature, to reduce regulatory burden and minimize future true-ups.[362]

376. J. Thygesen, on behalf of the CCA, recommended the accelerated depreciation parameters for this program should be denied.[363] He stated that the proposed accelerated depreciation method is driven by ATCO Electric's decision to replace existing meters with AMI meters on an accelerated basis, thus rendering any non-AMI meters obsolete. According to J. Thygesen, there is no difference between ATCO Electric's proposal and the Commission's findings in Decision 22394-D01-2018[364] denying EPCOR's requested relief to recover the undepreciated capital costs of conventional meters from its customers.[365] Finally, J. Thygesen noted that given the similarities between ATCO Electric's proposal and EPCOR's application addressed in the findings in Decision 22394-D01-2018, the net book value of existing meters should be to the account of shareholders.[366]

377. In its rebuttal evidence, ATCO Electric explained that the changes to the depreciation rates are in line with the conceptual principles of operating as a regulated utility as defined in the USA[367] and that a utility must have a reasonable opportunity to recover its prudently incurred costs.[368] Further, ATCO Electric stated its proposed treatment is different from EPCOR's

---

360 Exhibit 26615-X0023, ATCO Electric application, paragraph 88.
361 Decision 26354-D01-2021, paragraph 48.
362 Exhibit 26615-X0023, ATCO Electric application, paragraphs 84-86.
363 Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraph 103.
364 Decision 22394-D01-2018: Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities First Compliance Proceeding, Proceeding 22394, February 5, 2018.
365 Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraph 100 with reference to Decision 22394-D01-2018, paragraph 395.
366 Exhibit 26615-X0306, CCA evidence of J. Thygesen, paragraph 103.
367 Exhibit 26615-X0414, ATCO Electric rebuttal evidence, paragraph 105.
368 Exhibit 26615-X0414, ATCO Electric rebuttal evidence, paragraph 106.

treatment. EPCOR's "requested depreciation rate treatment was after-the-fact while ATCO Electric is requesting a forward-looking change to the depreciation rates for Account 371.10 to align depreciation expense with the expected future consumption of service value over the life of the assets in the account." Also, unlike EPCOR, ATCO Electric indicated that it will redeploy rather than immediately retire meters replaced by AMI meters as some AMR meters will be redeployed to areas that are not ready for AMI.[369]

378. Finally, ATCO Electric stated that its AMI replacement program and the proposed change in depreciation rates are directly correlated. If the AMI program is either accelerated or slowed down, then the useful lives of the AMR meters, and by extension, depreciation rates, would also require adjusting.[370]

379. The Commission agrees with the position of the CCA that the facts of this proposed change are not materially different from the facts related to EPCOR's request to retire its electro-mechanical and AMR meters as a result of the installation of EPCOR's AMI system. The Commission dealt with EPCOR's request in a series of decisions, specifically, Decision 3100-D01-2015,[371] Decision 20407-D01-2016,[372] and Decision 22394-D01-2018. The Commission has reviewed these decisions and finds that the reasoning in them applies to the circumstances of this case.

380. The Commission is of the view that the early retirement of ATCO Electric's AMR meters constitutes an "extraordinary retirement," in the terminology of the Utility Asset Disposition (UAD) Decision 2013-417,[373] with the result that the book value of the undepreciated meters would accrue to ATCO Electric's shareholder rather than customers if the project proceeds as planned. In the Commission's view, the retirement is extraordinary because it would constitute a sudden and complete obsolescence of these meters at the end of the six-year period, when viewed in the context of their existing service lives (currently approved to be 20 years) and given the subjectivity of ATCO Electric's chosen six-year service life, as noted below.

381. ATCO Electric had discretion to pursue a quicker pace of grid modernization and AMR meter replacement, but chose not to do so. There is nothing on the record of this proceeding that objectively anchors ATCO Electric's proposed six-year time period as the remaining expected useful life of its AMR meters. Concentric Advisors ULC's report ties the remaining six-year service life for AMR meters to the pace of ATCO Electric's GMP.[374] However, in its application ATCO Electric emphasized that it would not proceed with the replacement of its AMR meters if

369 Exhibit 26615-X0414, ATCO Electric rebuttal evidence, paragraphs 111, 119.
370 Exhibit 26615-X0414, ATCO Electric rebuttal evidence, paragraph 120.
371 Decision 3100-D01-2015: EPCOR Distribution & Transmission Inc., 2013 PBR Capital Tracker True-up and 2014-2015 PBR Capital Tracker Forecast, Proceedings 3216 and 3100, Applications 1610565 and 1610362, January 25, 2015.
372 Decision 20407-D01-2016: EPCOR Distribution & Transmission Inc., 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast, Proceeding 20407, February 7, 2016.
373 Decision 2013-417: Utility Asset Disposition: Proceeding 20, Application 1566373-1, November 26, 2013. The UAD decision was upheld by the Alberta Court of Appeal in *Fortis Alberta Inc. v Alberta (Utilities Commission)* 2015 ABCA 295.
374 Exhibit 26615-X0023, ATCO Electric application, Appendix E, Concentric report, PDF pages 119-120.

its depreciation rates were not approved.[375] On the other hand, during the oral hearing, ATCO Electric's President M. Bayley indicated that she was worried that the pace of grid modernization was too slow, notwithstanding the comments in the application that the program may not proceed.[376] This demonstrates the subjectivity involved in the pace of ATCO Electric's replacement program and the subjectivity involved in determining new depreciation rates.

382. The Commission is not persuaded that it is reasonable to adjust ATCO Electric's depreciation rates even though the Commission approved other elements of ATCO Electric's GMP. The Commission finds that great care must be exercised where a utility seeks to adjust its depreciation rates, which would have the effect of eliminating its stranded asset risk, where the proposed remaining expected service life of the assets in question is wholly within the utility's control. ATCO Electric's proposal to accelerate its depreciation rates in relation to this program is therefore denied. The Commission directs ATCO Electric to remove the $1.4 million in increased depreciation expense from its applied-for 2023 revenue requirement and recalculate its depreciation expense using the currently approved depreciation rates.

9 Compliance filings to this decision

383. Throughout this decision, the Commission has issued various directions to Fortis and ATCO Electric. The Commission directs each utility to file a compliance application to finalize its 2023 forecast revenue requirement to reflect the approvals, denials and adjustments in this decision by September 26, 2022.

384. 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 applications 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 and 2021 Transmission Access Charge Deferral Account true-up.
- Currently approved deferral accounts and rate riders, which shall continue to be applied in 2023. 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.

[375] Exhibit 26615-X0023, ATCO Electric application, PDF page 54, paragraph 173.
[376] Transcript, Volume 3, pages 442-444.

385. Further, both utilities included some hardcoded numbers for 2023 forecasts within their supporting Excel schedules. The Commission previously stated in Decision 22394-D01-2018 that the basis or derivation of any hardcoded numbers should be fully explained by providing a reference or source, or by fully describing what assumptions are used to obtain the underlying values.[377]

386. To assist the Commission in reviewing the compliance of Fortis and ATCO Electric 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.

387. Lastly, the Commission observes that in Fortis's case, the forecasting methodology used differs within some of its 2023 capital programs. For example, for the Facilities project within the General Support Program, a combination of three-year average of historical costs, adjusted for inflation, and bottom-up forecasting methods were used but it is not clear to the Commission which methodology was used for each project.[378] Accordingly, to ensure completeness and accuracy, Fortis is directed to update its summary table in IR response FAI-AUC-2022APR12-001[379] by reviewing each capital category and program and clearly identifying what forecasting methods it used. If necessary, additional rows may be added to the table to specify the forecasting method for each capital project within a program. The Commission will also use this table (along with supporting calculations as discussed in the previous paragraph) to ensure that the escalators approved in Section 5.2 of this decision have been applied in accordance with the Commission's findings.

10 Order

388. It is hereby ordered that:

(1) Each of ATCO Electric Ltd. (distribution) and FortisAlberta Inc. shall file a compliance filing in accordance with the directions set out in this decision by September 26, 2022.

Dated on July 28, 2022.

377 Decision 22394-D01-2018, paragraph 412.
378 For example, Fortis's application (Exhibit 26615-X0031, paragraph 402) and IR response (Exhibit 26615-X0444, PDF page 7) specify different forecasting methodologies for the Facilities project.
379 Exhibit 26615-X0444, FAI-AUC-2022APR12-001, PDF page 7, Table "Capital Category Program Forecast Method."

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) **Company name of counsel or representative**
ATCO Electric Ltd. (ATCO Electric) Bennett Jones LLP
FortisAlberta Inc. (Fortis or FAI)
Consumers' Coalition of Alberta (CCA) Bema Enterprises Ltd.
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP Russ Bell & Associates Inc.
Industrial Power Consumers Association of Alberta (IPCAA) Ackroyd LLP
Direct Energy Marketing Limited
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors
Alberta Federation of Rural Electrification Associations M. Joseph Redman

Alberta Utilities Commission Commission panel K. Sebalj, Vice-Chair C. Price, Commission Member B. Romaniuk, Acting Commission Member Commission staff L. Berg (Commission counsel) P. Khan (Commission counsel) E. Deryabina A. Jukov A. Spurrell B. Edwards S. Sharma N. Morter M. Logan

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
Consumers' Coalition of Alberta (CCA) J. Wachowich	D. Russell C. Benner
FortisAlberta Inc. (Fortis or FAI) B. Hunter C. Richards	B. Henderson C. Eck R. Tisdale A. Johnson B. Murray M. Dobner
ATCO Electric Ltd. (ATCO Electric) L. Smith S. Assie	C. Severson M. Sveinbjornson G. Hari M. Bayley K. Burgemeister
Office of the Utilities Consumer Advocate (UCA) T. Marriott K. Rutherford	
Industrial Power Consumers Association of Alberta (IPCAA) R. Penn R. Secord V. Bellissimo	
The City of Calgary (Calgary) D. Evanchuk	

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:
   - ATCO Electric is to use its actual labour cost increases for the period 2019-2020 in calculating its inflation escalator.
   - Fortis is to remove the materials price escalator from its inflation escalator for capital costs.
   - Both ATCO Electric and Fortis are to reduce their proposed customer growth escalator by 15 per cent. .... paragraph 5

2. The Commission directs each of ATCO Electric and Fortis to recalculate their respective 2023 forecasts under the mechanistic approach to reflect the escalation factors approved in this decision. Further, the Commission directs Fortis to remove the customer growth escalator from the calculation of its unit prices for all of its capital additions where the forecast was obtained by multiplying the unit prices (calculated using the escalated 2018-2020 average) by the number of units (estimated from the bottom up)............ paragraph 6

3. Having determined that using the 2018-2020 average of historical costs is acceptable, the Commission also reviewed Fortis's and ATCO Electric'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 chosen escalation factors. The same escalated 2018-2020 average costs were also used by each of ATCO Electric and Fortis 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 some 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 86

4. To avoid similar challenges in identifying the achieved efficiencies and calculating the realized savings at the next rebasing, the Commission directs Fortis and ATCO Electric 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. Fortis provided examples of some possible forward-looking productivity and/or efficiency measures, including: (i) controllable O&M per customer; (ii) controllable O&M per employee; (iii) controllable O&M per kilometre (km) of distribution line; (iv) controllable O&M per unit of energy consumed; (v) controllable O&M per demand; and (vi) total cost per km of distribution line and annual maximum capacity. ATCO

Electric offered O&M per km of line as a possible measure, but also stated that it is important to not forget about service quality measures. .... paragraph 91

5. Both ATCO Electric and Fortis relied on the same weightings between CPI and labour costs currently established for the I factor. Both used reliable data 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 Electric and Fortis to use the 2021-2023 CPI values as shown in tables 9 and 10 above in their respective compliance filings. .... paragraph 103

6. Regarding labour costs, ATCO Electric used the Alberta AWE index as a substitute for its labour costs escalator for 2019 and 2020, and used its own actual or projected labour cost increases for 2021-2023. The Commission finds Fortis's approach of using its own actual or forecast labour cost growth for the entire 2019-2023 period to be more methodologically sound than ATCO Electric's approach because it uses the same data for both historical and forecast costs. The Commission considers the use of the utilities' actual and forecast labour costs is reasonable because the objective of this proceeding is to realign the utility's costs with prices. Further, in Section 5.3 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 Electric to recalculate the 2019-2020 inflation index based its own labour cost data using the same methodology used for developing its 2021-2023 labour cost indexes as shown in Table 9 above. .... paragraph 104

7. For the reasons above, the Commission directs Fortis to remove the separate materials price component from its capital inflation escalator calculation. .... paragraph 107

8. As a result, the Commission finds that there is a need to introduce an offset to the customer growth escalation factors used by both utilities to account for its observations 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 124

9. The Commission finds that using the customer growth escalator to generate unit price forecasts is not reasonable because, as explained above, this escalator relates to the adjustment of volumes, not prices. For capital additions where Fortis used a bottom-up forecast based on a specific number of units or volume of work, there is no need for a separate customer growth escalator to escalate unit prices. The Commission directs Fortis to remove the customer growth escalator from the calculation of its unit prices for all of its capital additions where the forecast was obtained by multiplying the unit prices (calculated using the escalated 2018-2020 average) by the number of units (estimated from the bottom up). .... paragraph 128

approved amount of $17.1 million for this program. The Commission directs ATCO Electric to reflect this approved forecast for this program in its compliance filing. .... paragraph 210

16. The Commission has reviewed ATCO Electric's business case with respect to the vegetation management O&M program and, based on the information provided, is satisfied that the herbicide conversion of ATCO Electric's entire service area is reasonable based on the testing done in its western service territory during both PBR terms. The Commission finds ATCO Electric's evidence on the benefits of herbicide conversion to be persuasive and to permit a reasonable expectation of longer term cost benefits to consumers as well as enhanced safety and system reliability. ATCO Electric must follow all applicable regulations with respect to the type of herbicides used and how they are applied. Based on the above, the Commission approves ATCO Electric's 2023 forecast of $18.3 million for the vegetation management O&M account. The Commission also directs ATCO Electric to record the costs of the vegetation management O&M account over time and to be prepared to report on efficiencies realized in future proceedings. .... paragraph 218

17. With respect to ATCO Electric's submission that the $30.6 million forecast for 2023 has the potential to cause rate shock, in Decision 26521-D01-2021 the Commission allowed the DFOs to propose deferral treatment for some or all of the AESO customer contribution amounts that contribute significantly to rate shock. If such concerns arise in 2023, ATCO Electric is directed to consider this measure in its compliance filing to this decision. .... paragraph 225

18. In response to a Commission IR, ATCO Electric explained that it intends to true up its 2023 AESO customer contribution forecast amounts as a Y factor in future rate adjustment filings. This is consistent with the Commission direction in paragraph 21 of Decision 26521-D01-2021 where it approved the proposal to file an annual forecast for the AESO customer contribution Y factor amounts, which would then be subject to true-up in subsequent annual rate filings. Because the AESO customer contribution amounts will be recovered by way of a Y factor, the Commission directs ATCO Electric to exclude these amounts from its PBR3 going-in rates, which is similar to how other Y factor amounts are treated. .... paragraph 226

19. To ensure completeness and accuracy, Fortis is directed to update its summary table in IR response FAI-AUC-2022APR12-001 by reviewing each capital category and program and clearly identifying what forecasting methods it used. If necessary, additional rows may be added to the table to specify the forecasting method for each capital project within a program. The Commission will also use this table (along with supporting calculations as discussed in the previous paragraph) to ensure that the escalators approved in Section 5.2 of this decision have been applied in accordance with the Commission's findings. .... paragraph 238

20. Fortis did not provide the calculations underlying its forecast for the Customer Growth category. The Commission has therefore relied on Fortis's statement that the error was due to Fortis applying both the inflation and customer growth escalators to the historical 2018-2020 unit prices in determining its unit price forecast for this program. As discussed in Section 5.2 the Commission finds that it is not appropriate to apply a customer growth

escalator to unit price values. The customer growth escalator relates to the volume of work Fortis expects to complete, not the cost of that work. The Commission directs Fortis, in its compliance filing, to remove the application of the customer growth escalator from the determination of unit prices for the Customer Growth category. .... paragraph 244

21. The CCA and the UCA submitted that Fortis's WMP does not define target outcome and program scope carefully, does not consider cost constraints and cost effectiveness, and that data is manually connected and is not categorized by geographic area. The Commission agrees that Fortis's evidence in this proceeding neither demonstrates that it evaluates the performance of its WMP, nor that it collects data in a format that can later be analyzed when a wildfire does occur. Therefore, the Commission directs Fortis to provide, in the compliance filing, a cost-effective proposal to monitor the progress of its WMP and measure the effectiveness of the related capital expenditures. The proposal should include processes and procedures required to (i) track and report all details relating to wildfire incidents; (ii) identify the measures to be implemented to resolve the incidents; and (iii) assess the effectiveness of those measures in mitigating the incidents. .... paragraph 266

22. The Commission does not support the categorization of the secondary network upgrade project as new and non-recurring. As indicated in Fortis's business case and IR responses, Fortis completed service upgrades during the PBR2 term, and therefore the Commission is not persuaded that the costs associated with the secondary network upgrades required to support these service upgrades are not otherwise accounted for under Fortis's existing Externally Driven System Modifications Program. To approve Fortis's request for additional capital for a new program would be duplicative of the capital already provided in the Externally Driven System Modifications Program. Further, given that escalated 2018-2020 average capital additions were an input into Fortis's forecast for the Externally Driven System Modifications Program, the Commission sees no need to provide additional capital for this scope of work. The Commission expects that Fortis can continue to support such requests through funding provided for its recurring programs, as it has throughout the PBR2 term. The Commission directs Fortis to exclude the costs of the Secondary Upgrades Program from its 2023 forecast capital additions. .... paragraph 305

23. Accordingly, the Commission directs Fortis to remove the 2023 forecast capital additions for the Remote Community Reliability Program in its compliance filing. The Commission notes that the treatment of capital related to grid modernization and net-zero policies in PBR3 was included in the draft list of issues for Proceeding 27388. .... paragraph 311

24. For these reasons, the Commission finds that ATCO Electric's capital additions forecasts derived using the mechanistic approach, as adjusted by the escalation factors approved in Section 5.2, are reasonable. The Commission directs ATCO Electric to recalculate its 2023 capital additions forecast under the mechanistic approach to reflect the escalation factors approved in Section 5.2 of this decision. .... paragraph 316

25. The CCA and the UCA submitted that ATCO Electric's WMP was not supported by ATCO Electric system specific data and quantifiable measures to determine the cost-

effectiveness of the mitigation measures adopted. The Commission agrees that ATCO Electric's evidence in this proceeding neither demonstrates that it evaluates the performance of its WMP, nor that it collects data when a wildfire does occur. Therefore, the Commission directs ATCO Electric to provide, in the compliance filing, a cost-effective proposal to monitor the progress of its WMP and measure the effectiveness of the related capital expenditures. The proposal should include processes and procedures required to (i) track and report all details relating to wildfire incidents; (ii) identify the measures to be implemented to resolve the incidents; and (iii) assess the effectiveness of those measures in mitigating the incidents. .... paragraph 337

26. For these reasons, the Commission denies ATCO Electric's 2023 forecast capital additions for the Line Rebuilds, Replacements and Life Extensions Program that are above the escalated 2018-2020 average. Therefore, the Commission approves capital additions of $39.065 million, subject to adjustments resulting from using the escalation factors approved in Section 5.2, and directs ATCO Electric to remove the additional forecast costs above this amount from this program in its compliance filing. .... paragraph 350

27. Based on the foregoing, the Commission approves 2023 forecast capital additions of $11.122 million for the Transportation Equipment Program, and directs ATCO Electric to remove $4.527 million in capital additions for this program in its compliance filing. .... paragraph 363

28. To reflect the grant funding that ATCO Electric has secured for the ADMS project, the Commission directs ATCO Electric to remove 50 per cent of its 2023 forecast costs in the amount of $2.95 million for this project in its compliance filing. The Commission also directs ATCO Electric to provide the status of its NRCan grant applications for the AMI and Asset Modernization projects including any early information it may have on whether it is likely to secure the grants. If one or more of the grant applications are approved, ATCO Electric is directed to remove the amount of any grant funding amounts from its 2023 forecast costs for the relevant projects in the compliance filing. If the status of the grant application is not available at the time of the compliance filing, the Commission will consider whether any adjustments are required to ATCO Electric's forecasts for these projects based on the information provided at the time of the compliance filing. .... paragraph 373

29. The Commission is not persuaded that it is reasonable to adjust ATCO Electric's depreciation rates even though the Commission approved other elements of ATCO Electric's GMP. The Commission finds that great care must be exercised where a utility seeks to adjust its depreciation rates, which would have the effect of eliminating its stranded asset risk, where the proposed remaining expected service life of the assets in question is wholly within the utility's control. ATCO Electric's proposal to accelerate its depreciation rates in relation to this program is therefore denied. The Commission directs ATCO Electric to remove the $1.4 million in increased depreciation expense from its applied-for 2023 revenue requirement and recalculate its depreciation expense using the currently approved depreciation rates. .... paragraph 382

30. Throughout this decision, the Commission has issued various directions to Fortis and ATCO Electric. The Commission directs each utility to file a compliance application to

finalize its 2023 forecast revenue requirement to reflect the approvals, denials and adjustments in this decision by September 26, 2022. .... paragraph 383

31. To assist the Commission in reviewing the compliance of Fortis and ATCO Electric 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 386

32. Lastly, the Commission observes that in Fortis's case, the forecasting methodology used differs within some of its 2023 capital programs. For example, for the Facilities project within the General Support Program, a combination of three-year average of historical costs, adjusted for inflation, and bottom-up forecasting methods were used but it is not clear to the Commission which methodology was used for each project. Accordingly, to ensure completeness and accuracy, Fortis is directed to update its summary table in IR response FAI-AUC-2022APR12-001 by reviewing each capital category and program and clearly identifying what forecasting methods it used. If necessary, additional rows may be added to the table to specify the forecasting method for each capital project within a program. The Commission will also use this table (along with supporting calculations as discussed in the previous paragraph) to ensure that the escalators approved in Section 5.2 of this decision have been applied in accordance with the Commission's findings. .... paragraph 387

Appendix 4 – ATCO Electric forecast methodology

(return to text)

ATCO Electric	
O&M	
Grouping	**Methodology**
Supervision and Engineering	Mechanistic
Control Centre Operations	Mechanistic
Underground Line Expenses	Mechanistic
Street Lighting and Signal System Expenses	Mechanistic
Meter Expenses	Mechanistic
Miscellaneous Distribution Expenses	Mechanistic
Line Transformers	Mechanistic
Supervision	Mechanistic
Meter Reading Expenses	Mechanistic
Customer Records and Collection Expenses	Mechanistic
Uncollectible accounts	Mechanistic
Customer assistance expenses	Mechanistic
Informational and instructional advertising expenses	Mechanistic
Miscellaneous customer service and informational expenses	Mechanistic
Office Supplies and Expenses	Mechanistic
Outside Services Employed	Mechanistic
Insurance Premiums	Mechanistic
Injuries and Damages	Mechanistic
Board Expenses	Mechanistic
Miscellaneous General Expenses	Mechanistic
Head Office Rent	Mechanistic
Board Disallowed Expenses	Mechanistic
Load Settlement	Mechanistic
Isolated Generation Operations & Maintenance	Mechanistic
Allocated Share of General Operations & Maintenance	Mechanistic
Overhead Line Expenses	Non-mechanistic
Vegetation Management	Non-mechanistic
Administrative and General Salaries (Limited to Incremental Costs)	Non-mechanistic
Information Technology Costs	Non-mechanistic
Capital	
Externally Driven System Modifications	Mechanistic
Environment Reliability and Safety	Mechanistic
Metering	Mechanistic
Forestry Protection	
Clearance and Safety (Vegetation Management portion)	Mechanistic
Wildfire Risk Reduction	Non-mechanistic
Rebuilds, Replacements and Life Extensions	
Wood Pole Replacements & Life Extensions	Mechanistic
Underground Rebuilds, Replacements & Life Extensions	Mechanistic
Overhead Line Rebuilds, Replacements & Life Extension	Non-mechanistic

ATCO Electric	
General Support	
Buildings, Structures & Leasehold Improvements	Mechanistic
Communication Structures and Equipment	Mechanistic
Tools and Instruments	Mechanistic
Information Technology Related	Mechanistic
Transportation Equipment	Non-mechanistic
Customer Growth	
New Extensions	Non-mechanistic
Non-Recurring	
CIS Replacement	Non-mechanistic
Grid Modernization	Non-mechanistic

Source: Exhibit 26615-X0023, ATCO Electric application, PDF pages 33-34 and 48-49.

Appendix 5 – Fortis forecast methodology

(return to text)

Fortis	
Capital	
Grouping	**Methodology**
Customer Growth	Non-mechanistic
Externally Driven System Modifications	
Distribution Line Moves	Mechanistic
High Load Corridor Clearances	Mechanistic
Distribution Capacity Increases	Non-mechanistic
Substation Associated Upgrades	Non-mechanistic
Independent Power Producer Interconnections	Non-mechanistic
Distributed Energy Resources (DER) Integration	Non-mechanistic
Environment, Safety and Reliability	
Compliance, Safety & Reliability	Non-mechanistic
Worst Performing Feeders	Non-mechanistic
Aging Facilities	Mechanistic
SCADA	Non-mechanistic
Rebuilds, Replacements and Life Extensions	
Pole Management Program	Non-mechanistic
Urgent Repairs	Non-mechanistic
Cable Management	Non-mechanistic
Apparatus Predictive Replacement	Non-mechanistic
LED Streetlights	Non-mechanistic
Bulk Lamp Replacements	Mechanistic
Forestry Protection	
Previously Trimmed Tree Removal	Mechanistic
Forest Protection Area Maintenance	Mechanistic
Wildfire Mitigation	Non-mechanistic
Metering	
Metering	Non-mechanistic
General Support	
Facilities	Non-mechanistic
Tools and Instruments	Non-mechanistic
Transportation and Equipment	Non-mechanistic
IT Hardware & Software	Non-mechanistic
Non-Recurring Capital	
System Purchases (REAs, Annexation)	Non-mechanistic
Distribution Voltage Management	Non-mechanistic
Secondary Upgrades	Non-mechanistic

*Fortis forecast all O&M with a bottom-up approach.
Source: Exhibit 26615-X0444, FAI-AUC-2022APR12-001, PDF pages 6-7.