Alberta Utilities Commission

EPCOR Distribution & Transmission Inc.

2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates

December 13, 2022

Alberta Utilities Commission
Decision 27653-D01-2022
EPCOR Distribution & Transmission Inc.
2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates
Proceeding 27653
Applications 27653-A001 and 27653-A002

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Contents

List of figures

List of tables

EPCOR Distribution & Transmission Inc.
2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates

Decision 27653-D01-2022
Proceeding 27653

1 Decision summary

1. In this decision, the Alberta Utilities Commission considers EPCOR Distribution & Transmission Inc.'s compliance with Decision 26617-D02-2022[1] and its resulting 2023 distribution rates. For the reasons that follow, the Commission has determined that:

- EPCOR complied with Decision 26617-D02-2022, and therefore, the Commission approves the resulting 2023 forecast revenue requirement.
- The Commission approves EPCOR's 2021 annual transmission access charge deferral account (TACDA) true-up amount.
- The 2023 distribution rates, riders and corresponding rate schedules, are approved effective January 1, 2023, subject to the filing of post-disposition documents reflecting adjustments to the Residential customer class consumption forecast as directed in this decision by December 19, 2022.
- The 2023 system access service (SAS) transmission rates as filed and set out in Appendix 4 are approved effective January 1, 2023.
- Determinations regarding the setting of 2023 maximum investment levels (MILs) will be made under Proceeding 27658, Residential standards of service and MILs. The Commission makes no findings in regard to EPCOR's MILs in this decision.

2 Introduction and background

2. Since 2013, rates for the electric and natural gas distribution utilities under the Commission's jurisdiction have been set under performance-based regulation (PBR).[2] PBR plans applied to the four large electric distribution facility owners (DFOs): ATCO Electric Ltd., FortisAlberta Inc., ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc.; and the two large natural gas DFOs: ATCO Gas and Pipelines Ltd., and Apex Utilities Inc.

[1] Decision 26617-D02-2022: ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., 2023 Cost-of-Service Review, Proceeding 26617, July 28, 2022.
[2] Until 2015, ENMAX Power Corporation was regulated under a different form of PBR, a 2007-2013 formula-based ratemaking plan followed by cost-of-service rebasing in 2014.

3. Under the PBR plans that ran from 2013 to 2017 (PBR1)[3] and 2018 to 2022 (PBR2),[4] each utility's rates (or revenue-per-customer in the case of gas DFOs) were adjusted annually by means of an indexing mechanism that tracked the rate of inflation (I factor), less an offset to reflect the productivity improvements each DFO was expected to achieve during the PBR plan period (X factor), plus other specific adjustments. These other adjustments included the ability to flow-through certain costs that should be recovered from, or refunded to, customers directly (Y factors), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (Z factor). As well, K and K-bar factor adjustments served to provide supplemental capital funding. As a result, with the exception of these specifically approved adjustments, during a PBR term, a utility's revenues were no longer linked to its costs. This decoupling of costs and revenues was intended to promote behaviours that increase productivity and decrease costs.

4. At the end of the PBR2 plan, each DFO's costs and revenues were realigned through a "rebasing" process[5] that involved a one-year cost-of-service (COS) review based on 2023 forecast costs. 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 operation and maintenance (O&M) and administrative expenses of the company plus the utility's capital-related costs (depreciation, interest on debt, and return on equity). Rates are then established by dividing the revenue requirement for each customer class by the billing units (such as the monthly charge, or dollars per kilowatt hour (kWh).

5. For the utilities EPCOR and ENMAX, the 2023 rebasing was considered by way of a negotiated settlement agreement (NSA). The Commission issued Decision 26617-D01-2022[6] approving the NSA, and Decision 26617-D02-2022 providing reasons on doing so, as well as instructing ENMAX and EPCOR on additional filings required for this proceeding.

6. In Decision 26617-D02-2022, the Commission determined that the 2023 rates, established as a result of the 2023 COS review, will be used as "going-in rates" for the next PBR term, referred to as PBR3, that will commence on January 1, 2024.

7. In Decision 26617-D01-2022, the Commission accepted the NSA reached between EPCOR and the Office of the Utilities Consumer Advocate (UCA) as reasonable, and subsequently in Decision 26617-D02-2022, the Commission directed EPCOR to file a compliance filing to the decision, including all information that typically accompanies the calculation of rates, including the following:

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

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

[5] As explained in Decision 20414-D01-2016 (Errata), paragraph 26, depending on the context, the word "rebasing" can be used as a noun (the process of rebasing); an adjective (the rebasing process); or as a verb (the process involves rebasing costs and revenues).

[6] Decision 26617-D01-2022: ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., 2023 Cost-of-Service Review, Proceeding 26617, June 20, 2022.

- A 2023 billing determinant forecast reflective of the last approved Phase 2 methodologies and most recent data.
- A 2023 distribution tariff based on the approved revenue requirement and the associated bill impact analysis.
- Terms and conditions of service for 2023 for approval.
- A 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.
- All 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.[7]

8. The Commission has 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.

3 Compliance with Decision 26617-D02-2022

9. In Decision 26617-D02-2022, the Commission ordered EPCOR to revise its applied-for 2023 revenue requirement to reflect the Commission's approval of the NSA.

10. In Proceeding 26617, EPCOR requested a 2023 distribution access service (DAS) COS forecast revenue requirement of $275.14 million (not including franchise fees of an additional $72.8 million). As part of the NSA that EPCOR entered into in Proceeding 26617, EPCOR agreed to a total reduction to its applied-for revenue requirement of $6.2 million, which also included a revenue requirement reduction of $800,000 due to errors and omissions.[8] DAS rates are based on a distribution revenue requirement of $268.96 million in 2023 as a result of the NSA.[9]

11. The Commission finds that EPCOR complied with the directions in that decision in the formulation of its application, other than where exceptions are explained below and some changes will be required. The Commission, therefore, approves the resulting 2023 forecast revenue requirement of $268.96 million. The specific calculations of rates and formulations of the factors incorporated into EPCOR's 2023 rates are discussed in the following sections.

4 2023 rate adjustments

12. As noted above, this proceeding was designed to not only be the compliance filing to Decision 26617-D02-2022, but to also determine rates for 2023, based on the revenue

7 Decision 26617-D02-2022, paragraph 63.
8 Proceeding 26617, Exhibit 26617-X0030, Attachment 2.
9 Exhibit 27653-X0002, application, paragraph 60.

requirement resulting from the approvals in that decision. As such, the Commission has reviewed the rate adjustment aspect of this application in much the same way as it has done in past annual PBR rate adjustment filings.

4.1 Y factor deferral accounts

13. Under PBR, Y factor includes costs that do not qualify for capital treatment or Z factor treatment that the Commission considers should be directly recovered from customers or refunded to them. EPCOR applied for the inclusion of the Y factor amounts in its 2023 rates as these cost items continue to be subject to the previously established deferral account treatment in the 2023 COS year.

14. A summary of the proposed Y factor amounts is shown in Table 1:

Table 1. Applied-for 2023 Y factor amounts[10]

Y factor	Total true-up amount ($ million)
AESO [Alberta Electric System Operator] Flow Through Items	(0.01)
AUC Assessment Fees	(0.18)
Effects of Regulatory Decisions	-
Intervener Costs	(0.00)
Commission Tariff Billing & Load Settlement Initiatives	0.03
Property, Business & Linear Taxes	1.10
Distribution AESO Contributions to Transmission	-
Carrying Charges [see section 4.1.1]	0.04
ECM [see Section 4.1.2]	3.03
Total	**4.01**

15. All of the Y factor adjustments proposed by EPCOR were approved for Y factor treatment in Decision 2012-237. As can be seen in the table above, EPCOR is not proposing any Y factor adjustments related to regulatory decisions or distribution AESO contributions to transmission. The AUC tariff billing and load settlement initiatives are a result of Commission directions, and therefore approved as a flow-through item. The amount to be collected in this compliance filing is comprised of the actual amounts incurred from August 1, 2021, to July 31, 2022, as part of EPCOR's project to modify its Settlement Tariff Analysis and Revenue System to comply with changes to the Rule 021: *Settlement System Code Rules*.

16. With the exception of carrying costs and Efficiency Carryover Mechanism (ECM) amounts (addressed in sections 4.1.1 and 4.1.2 of this decision, respectively), the Commission has assessed the amounts included in EPCOR's applied-for Y factor and finds they were adequately supported, properly calculated and in compliance with previous Commission directions. The Commission reviewed EPCOR's Y factor carrying costs and finds that they were not properly calculated in accordance with the applicable provisions of Rule 023: *Rules Respecting Payment of Interest*. Accordingly, the applied-for Y factor amount is approved as filed with the exception of the correction required to the carrying costs as explained in the section below.

10 Exhibit 27653-X0002, 2023 COS Compliance Application, PDF page 11, Table 5.1-1; Exhibit 27653-X0006.02, Appendix F – 2023 Rate Design – ECM revised, Excel cell R206.

4.1.1 Y factor carrying charges

17. Regarding the payment of interest, Rule 023 states that, "Interest will be calculated from the date the balance, adjustment or cost is outstanding using simple interest at the Bank of Canada policy interest rate plus 1¾ per cent, unless otherwise directed. The rate will be calculated on a per annum basis."[11]

18. The Commission notes that Rule 023 prescribes using simple interest. EPCOR is calculating its carrying costs on the current outstanding Y factor balance, plus prior period carrying costs.[12] This is equivalent to a compound interest approach rather than the simple interest approach that is prescribed in Rule 023. Therefore, EPCOR's calculation requires a correction.

19. EPCOR is directed to recalculate the Y factor carrying costs amount using simple interest calculations and ensure compound interest is not used in any other interest payment calculations subject to Rule 023, and to file updated schedules reflecting these changes as post-disposition documentation in this proceeding, by December 19, 2022.

4.1.2 ECM amount

20. The PBR plan produces an incentive to find efficiencies that weakens as the end of the PBR term approaches because there is less time remaining for the utility to benefit from any efficiency gains. The Commission approved the inclusion of the efficiency carryover mechanism, or ECM, to maintain incentives by permitting the utilities to carry a portion of earnings in excess of the approved return on equity (ROE) from the prior PBR term to the following years. The ECM was approved for both of the PBR1 and PBR2 plans. This helps to reinforce the efficiency incentive of PBR throughout the term.

21. Specifically, the ECM ROE add-on is calculated as 50 per cent of the difference between the average allowed and average actual ROE over the course of a PBR term, with an upper limit of 0.5 percentage points. This ROE add-on would apply for two years after the end of a PBR plan and is collected by way of a Y factor.[13]

22. In Decision 20414-D01-2016 (Errata), the Commission pointed out that it is necessary to determine the rate base or rate bases to which the approved ROE add-on percentage will be applied in order to calculate the associated ECM dollar amount that will be included in customer rates. In that decision, the Commission approved an ECM calculation based on the mid-year rate base during the final year of the PBR1 term. Consistent with the overall approach to the PBR2 rebasing, the Commission directed the final approved 2017 notional mid-year rate base as the value to which the approved ROE add-on percentage would be applied. The calculated ECM dollar amount was escalated by the approved I-X value for 2018 and 2019 to arrive at the ECM dollar amounts for each of those years. Finally, in that decision, the Commission stated that the

[11] Rule 023, Section 3(3), effective date March 1, 2022.

[12] Exhibit 27653-X0010, Appendix L – True-ups, tab 'Y Factor True-up Carrying Costs,' Table 3 - This calculation can be seen where the interest rate is calculated by adding the 'Y-Factor True-Up' outstanding balance to the previous period's carrying costs amount in the column 'Calculation of Carrying Costs' and then multiplying that sum by that month's interest rate. This calculates future interest upon past interest amounts, and therefore is not in accordance with Rule 023's direction to use simple interest.

[13] Decision 20414-D01-2016 (Errata), paragraphs 79 and 85.

same ECM calculation would also apply to determine the ECM dollar amounts for the PBR2 term.[14]

23. EPCOR showed that, based on its returns over the PBR2 term, it qualifies for the maximum allowed ECM ROE add-on of 0.5 percent.[15] EPCOR calculated the interim 2023 ECM dollar amount of $3.03 million by applying the add-on of 0.5 per cent to the 2022 forecast mid-year rate base. EPCOR pointed out that this amount needs to be trued up to reflect actual 2022 rate base and ROE.

24. Further, to align with the findings in Decision 20414-D014-2016 (Errata), EPCOR proposed to escalate the calculated ECM dollar amount by I-X for each of 2023 and 2024. EPCOR stated that an I-X value for 2023 can be calculated using the inflation factor methodology and X factor approved for use in the PBR2 term. The I-X value for 2024 would be approved in the PBR3 plan.[16]

25. In EPCOR's view, its proposed calculation aligns with the Commission's direction in Decision 20414-D01-2016 (Errata), that an ECM calculation should be based on the mid-year rate base during 2017, the final year of the PBR term.[17]

26. In an information request, the Commission asked EPCOR to comment on the use of the 2023 forecast mid-year rate base in the ECM calculation, as was done by ATCO Electric, ATCO Gas and Fortis. In response, EPCOR observed that such approach is less consistent with the Commission's determinations in Decision 20414-D01-2016 (Errata), but would still support just and reasonable rates.[18] EPCOR also noted that there is no need to escalate by I-X the ECM amount calculated in this way for 2023 as it reflects the approved rate base for 2023.

27. The UCA stated that the determination of the ECM should be based on the 2022 forecast rate base as approved in this proceeding. Regarding if an escalation factor should be applied to the ECM calculation, the UCA stated that because the intent of the ECM is to provide compensation for efficiencies gained during a PBR year, there should be no reason for the amounts to be inflated beyond the PBR term.[19]

28. The Commission finds that the 2023 ECM dollar amount will be calculated based on the 2022 actual approved mid-year rate base. In Decision 20414-D01-2016 (Errata), the Commission based the ECM calculation on the mid-year rate base during the final year of the PBR term. In support of this approach, the Commission stated that because the ECM ROE add-on percentage is calculated based on a utility's earnings in the PBR term, it should not be applied to the actual rate base amounts outside of that term.[20] The Commission continues to find this approach to be reasonable and further notes that to the extent a utility's 2023 rate base is different from its 2022 rate base, basing the ECM calculation on the 2023 mid-year rate base may result in windfall gains or losses to the utility, which is not the intent of the ECM.

14 Decision 20414-D01-2016 (Errata), Appendix 5, PDF page 100.
15 Exhibit 27653-X0036.01, ECM Calculation.
16 Exhibit 27653-X0040, EDTI-AUC-2022OCT21-006(a).
17 Decision 20414-D01-2016 (Errata), paragraphs 83-84.
18 Exhibit 27653-X0046, EPCOR argument, paragraph 17.
19 Exhibit 27653-X0045, UCA argument, paragraph 16.
20 Decision 20414-D01-2016 (Errata), paragraph 83.

29. In Decision 20414-D01-2016 (Errata), the Commission explained that the choice of the 2017 notional mid-year rate base (rather than an actual 2017 rate base) was reflective of the overall rebasing approach for the PBR2 plan.[21] In the Commission's view, such choice was not meant to create an inconsistency with the separate determination to base the ECM calculation on the mid-year rate base of the final year of the PBR term.

30. The Commission agrees with EPCOR's view that the 2023 ECM amount should be trued up to reflect the actual 2022 rate base given the determinations in Decision 26617-D02-2022 that the 2022 actual closing rate base will form the basis of the mid-year rate base used to form going-in rates for the PBR3 term.[22] Also, a true-up may be required to reflect the actual 2022 ROE as it may affect the ECM ROE add-on percentage.

31. EPCOR also pointed out that an ECM dollar amount calculated using the 2022 mid-year rate base should be escalated for 2023 and 2024, consistent with the methodology approved in Decision 20414-D01-2016 (Errata). The Commission finds that the I-X index from the PBR2 plan is not applicable for an intervening 2023 COS year. The Commission finds it is reasonable to escalate the ECM dollar amount using the 2023 COS inflation escalator. Doing so is consistent with the overall COS approach to rebasing.

32. Since EPCOR's rebasing process was subject to a negotiated settlement, the Commission did not review and approve a single inflation escalator for EPCOR. In Decision 26615-D01-2022,[23] the Commission reviewed in depth and approved COS inflation escalators for Fortis and ATCO Electric based on each DFO's actual or forecast salary increases and the Alberta Consumer Price Index (CPI). After revisions as directed by the Commission in Decision 26615-D01-2022, both ATCO Electric and Fortis have approved COS inflation escalators of 2.68 per cent. Given that all DFOs face similar inflationary pressures captured by the Alberta CPI, and based on the Commission's observation that the 2023 labour escalators of all four electric DFOs track reasonably close,[24] the Commission finds it reasonable to apply the same 2023 COS inflation escalator of 2.68 per cent for the purposes of calculating EPCOR's 2023 ECM amount.

33. As the PBR3 plan starts on January 1, 2024, the Commission finds that the 2024 ECM dollar amount should be escalated by the index approved in the PBR3 plan, as proposed by EPCOR.

34. Given the interim nature of the 2023 ECM amount (as explained above), there is no need to update the 2023 rates at this time. The Commission directs EPCOR to true up its 2023 ECM dollar amount, reflecting the methodology approved in this decision, upon the approval of the 2022 actual rate base.

4.2 Cost-of-capital true-ups

35. In its application, EPCOR included true-ups for its actual 2021 weighted average cost of capital (WACC), reflecting the actual cost of debt for 2021. The following sections address the

[21] Decision 20414-D01-2016 (Errata), paragraph 84.
[22] Decision 26617-D02-2022, paragraph 57.
[23] Decision 26615-D01-2022: ATCO Electric Ltd., FortisAlberta Inc., 2023 Cost-of-Service Review, Proceeding 26615, July 28, 2022.
[24] Decision 26615-D01-2022, Table 9 (ATCO 2.75% union/non-union blended) and Table 10 (Fortis labour escalator 2.5%); Exhibit 26617-X0046.01, EPCOR application, Table 1.5.1.3-1 (Non Union escalator 2.75%), Table 1.5.1.4-1 (Union escalator 2.5%).

true-ups related to the actual WACC rate true-up for the 2021 K-bar and for Customer Specific (CS) rates CS24, CS40 and CS46.

4.2.1 K-bar true-up

36. K-bar funding provides incremental Type 2 capital funding to supplement the revenues generated under the I-X mechanism.[25] Consistent with directions set out in Decision 20414-D01-2016 (Errata), EPCOR adjusted its 2021 K-bar calculation to reflect the actual 2021 cost of debt in its actual 2021 WACC rate. This actual WACC rate adjustment results in a 2021 K-bar true-up refund of $4.97 million plus an associated carrying costs refund of $0.35 million, for a total 2021 K-bar refund to customers of $5.32 million.[26]

37. Consistent with the direction in Section 4.1.1 regarding the Y factor carrying costs, the K-bar true-up carrying costs must be recalculated so they are consistent with Rule 023. As with the Y factor true-up carrying costs, EPCOR's K-bar carrying costs were calculated by adding prior period carrying costs to the outstanding principal, and then the current period's interest amount (or carrying costs) was calculated on that sum of principal and interest.[27] This is equivalent to a compound interest approach rather than a simple interest approach that is prescribed in Rule 023. Therefore, EPCOR's calculation requires a correction.

38. No party objected to the K-bar true up calculation and the Commission approves the true-up as filed with the exception of the correction required to the K-bar carrying cost calculation. The Commission directs EPCOR to recalculate the K-bar true-up carrying costs amount using simple interest calculations and ensure compound interest is not applied in any other carrying cost calculations that are subject to Rule 023.

4.2.2 2021 CS rate true-ups

39. EPCOR did not apply for any new proposed CS customer rates in the application, but commented on rate updates for several CS rates.

40. When approving CS rates for the CS46, CS24 and CS40 customers, the Commission directed EPCOR to true up these rates to reflect (i) the actual in-service date if it differed from the approved in-service date; and (ii) the actual WACC rate for 2021. EPCOR stated that no true-ups were required for the in-service dates of these three customers because the updated rates took effect on the applied-for dates. EPCOR updated the rate calculations for rates CS46, CS24 and CS40 to reflect the actual 2021 cost of debt. The actual cost of debt was 5.74 per cent while the placeholder WACC rate used was 6.06 per cent for CS46 and CS24, and 5.84 per cent for CS40.[28] A summary of the true-up amounts is provided in Table 2 below.

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25 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, paragraph 167.

26 Exhibit 27653-X0002, application, Table 5.2-1 2021 K-Bar True-Up.

27 Exhibit 27653-X0010, Appendix L, tab '2021 K-Bar Carrying Costs,' Table 3.

28 Exhibit 27653-X0002, application, paragraph 58.

Table 2. Cost of debt true-ups for certain CS rates

CS rate	True-up amount ($)
CS46	(9,541)
CS24	(4,999)
CS40	(216)

41. EPCOR proposed to process the true-up amounts as one-time adjustments for each of CS46, CS24 and CS40 rates, with the adjustments to be included with the January 2023 charges. The Commission agrees that doing so is an acceptable method of implementing the 2021 WACC true-up and approves the refund amounts listed in Table 2 above. In Section 6.2, the Commission assesses the bill impact of EPCOR's 2023 rates (including the CS46, CS24 and CS40 rates) and approves them.

4.3 2023 billing determinant forecast

42. Forecast billing determinants are used to allocate a DFO's revenue requirement to rate classes and to calculate the resulting rate adjustments, and are also used in performing the annual use-per-customer adjustments for gas distribution utilities.

43. In the application, EPCOR provided detailed 2023 billing determinant forecasts.[29] EPCOR submitted that its 2023 billing determinants were forecast based on the methodology approved in its recent Phase 2 decision.[30]

44. The Commission asked EPCOR to provide information on any variances from forecast to actual billing determinants by rate class and identify the cause of variances larger than ± five per cent, and EPCOR provided those explanations.[31] There were variances larger than ± five per cent for the Medium Commercial, Direct Connects, Customer Specific, Customer Specific – Totalized and Street Lights rate classes in 2021.

45. The Commission considers that identified variances from forecasts such as those described by EPCOR for 2021 are reasonable. Such occurrences do not generally call into question the predictive value of the methodology used to generate such forecasts. The Commission directs EPCOR to continue to provide information on any variances from forecast to actual billing determinants by rate class and to identify the cause of variances larger than ± five per cent on an annual basis.

46. No party objected to EPCOR's billing determinant forecast or its variance explanations. Based on its review and assessment of EPCOR's methodology and billing determinants in this proceeding, the Commission finds that the methodology and the resulting 2023 forecast billing determinants are reasonable and are approved with the exception of the Residential customer class consumption forecast for reasons explained in the section below.

[29] Exhibit 27653-X0003, Appendix B EPCOR Billing Determinant Forecast.

[30] Exhibit 27653-X0002, application, paragraph 21; Decision 27018-D01-2022: EPCOR Distribution & Transmission Inc., Phase 2 Distribution Tariff Application, Proceeding 27018, July 11, 2022.

[31] Exhibit 27653-X0040, EDTI-AUC-2022OCT21-003.

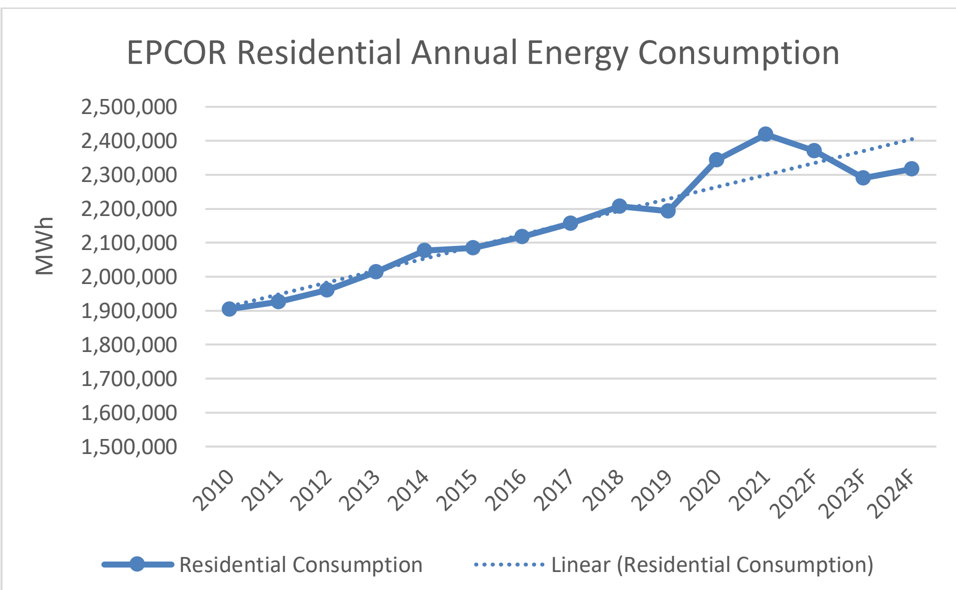
4.3.1 Forecast billing determinants for residential class

47. EPCOR's 2023 billing determinants (e.g., energy consumption) forecast for the residential rate class is not approved as filed as the Commission finds it to be unreasonable.

48. The Commission recognizes EPCOR based its 2023 residential consumption forecast using the approved regression model from its 2022 Phase 2 proceeding. The Commission notes this is the first time the new forecasting model is used in a proceeding to determine billing determinants forecast that will be used in calculating EPCOR's distribution rates, so this is the first proceeding to test the validity of the model's results.

49. The Commission is not satisfied with the resulting forecast for the residential class as it departs too far from historical trends. Figure 1 below is a graph prepared by Commission staff showing the residential class historical consumption and the forecast values submitted by EPCOR in this proceeding by year. EPCOR forecast for 2022 is 2,370,916 MWh, for 2023 is 2,290,370 MWh, reflecting a decrease in consumption, followed by an increase in 2024 to be 2,316,724 MWh.[32]

Figure 1. EPCOR Residential class consumption trend



50. The dotted linear trend line in the figure above shows that the 2023 and 2024 forecasts submitted by EPCOR are markedly below the historical trend of increases in residential class consumption between 2010 and 2019, prior to the pandemic's influence on consumption. Pandemic restrictions appear to have impacted some customer class consumption levels for the years 2020 to 2022, but the Commission has no reason to believe that residential consumption will over-correct to levels lower than the historical growth pattern in EPCOR's service territory.

51. EPCOR stated, "All Alberta Government mandated COVID-19 related restrictions have now been removed and the residential energy usage per customer has returned to pre-pandemic

[32] Exhibit 27653-X0003, Appendix B EPCOR Billing Determinant Forecast, "Model Summary." 2022 modified for July, August actuals in EDTI-AUC-2022OCT21-004 Attachment 1.

or near pre-pandemic levels."[33] This statement would appear to support a return to a traditional residential class growth trend, which the Commission believes would translate to the expectation of a 2023 consumption forecast more in line with the historical trend.

52. EPCOR predicted a 3.4 per cent decline in consumption from 2022 forecast levels.[34] The Commission notes EPCOR had its two highest months for residential consumption in December 2021 and January 2022 since 2001.[35] Additionally, when EPCOR updated its July and August 2022 actual monthly consumption values from forecast values created by its regression model in an IR response,[36] the actuals were nine and 17 per cent higher than the 2022 forecast values for those months. This further indicates that forecast levels predicted by EPCOR's recently approved regression model appear to be low. All the previously described factors indicate to the Commission that it is unlikely that a residential consumption will decline in 2023 below historical trends.

53. Due to the above, EPCOR's 2023 residential consumption forecast is denied, and EPCOR is directed to use the growth rate average of the last 10 years of actual growth (2012-2021) and apply that to the most recent 2022 residential consumption forecast including updates for September and October actual consumption to obtain the revised 2023 residential consumption forecast.

54. This adjustment does not mean that EPCOR should discontinue to use the regression model used for forecasting its billing determinants as approved in Decision 27018-D01-2022. The deviation from the forecast directed by the Commission in this decision is based on its findings regarding the impact of COVID-19 pressures on residential consumption over the 2020-2022 period and only applies for determining the 2023 residential consumption forecast. The Commission directs EPCOR to comment on the regression model accuracy as compared to historic trend and actuals in its application dealing with 2024 distribution rates.

5 2021 TACDA true-up

55. All electric distribution utilities accessing the electric transmission system in the province are charged by the AESO for transmission services provided in relation to customers in their service areas. The purpose of the annual TACDA true-up is to ensure that revenues collected through a distribution utility's transmission access charges in a year recover the AESO tariff charges paid by the utility in that year.

56. In the PBR plans, as a dollar-for-dollar flow-through of the AESO tariff charges, TACDA costs were eligible for Y factor treatment. The same treatment is extended to the 2023 COS year. The utility does not assume any volume or price risk, but also does not earn any return, nor risk losses, in flowing through these costs to customers.

33 Exhibit 27653-X0040, EDTI-AUC-2022OCT21-002.

34 Exhibit 27653-X0040, Table EDTI-AUC-2022OCT21-001-1 Energy Update, Updated Weather revised forecasts: 2023 forecast consumption of 2,290,370 MWh / 2022 forecast consumption 2,370,916 MWh – 1 = -3.4%. (2022F is from Exhibit 27653-X0041, EDTI-AUC-2022OCT21-004 Attachment 1, Table EDTI-AUC-2022OCT-21-004-02 Updated Actuals, sum of Residential months.

35 Exhibit 27653-X0040, EDTI-AUC-2022OCT21-004(d).

36 Exhibit 27653-X0041, EDTI-AUC-2022OCT21-004 Attachment 1, Table EDTI-AUC-2022OCT-21-004-02.

57. The annual TACDA true-up schedules are based on the harmonized framework approved by the Commission for all four distribution utilities in Decision 3334-D01-2015.[37] EPCOR's 2020 TACDA true-up was approved in Decision 26852-D01-2021.[38]

5.1 Total 2021 TACDA net true-up amount

58. EPCOR applied for a net 2021 TACDA collection of $1.81 million from customers. The components of the total true-up amount applied for are listed in Table 3 and are further described in this section.

Table 3. Components of the applied-for 2021 TACDA true-up Rider J

Component	True-up amount collection/(refund) ($ million)
2019 TAC deferral account true-up	0.10
2021 SAS deferral true-up	2.51
2021 AESO deferral account reconciliation (DAR) true-up	(0.91)
2021 Balancing Pool true-up	(0.07)
Carrying costs	0.19
Total collect/(refund)	**1.81**

Source: Exhibit 27653-X0021, Appendix 1, Schedule 1.0.

59. The deferral account rider true-up ensures that the amounts actually collected or refunded through a previously approved rider equal the amounts approved by the Commission. In a 2020 decision, EPCOR was approved to collect $3.82 million through TACDA true-up Rider J over a 12-month period in 2021.[39] The actual collection was $3.72 million, necessitating a further collection of $0.1 million.

60. The SAS deferral true-up ensures the actual transmission access revenues received from SAS rates and related quarterly riders equals the actual transmission costs incurred. EPCOR's total 2021 transmission access revenues for distribution-connected customers, including revenues received or amounts refunded through its quarterly TACDA true-up riders, amounted to $256.5 million which, compared to total costs of $259.01 million, results in a required collection of $2.51 million.

61. The AESO DAR deals with any variances between the actual costs the AESO incurs and the revenues it receives to ensure that "… on an annual basis, no profit or loss results from its operation."[40] Any such variances are refunded to, or recovered from, market participants by way of the AESO DAR, typically undertaken on an annual basis. The distribution utilities flow through these collections or refunds to customers in their service areas. The Commission approved the AESO's 2021 DAR in Decision 27547-D01-2022.[41] The reconciliation will result

[37] Decision 3334-D01-2015: Commission-Initiated Review, Electric Transmission Access Charge Deferral Accounts – Annual Applications, Proceeding 3334, Application 1610728-1, July 21, 2015.

[38] Decision 26852-D01-2021: EPCOR Distribution & Transmission Inc., 2022 Annual Performance-Based Regulation Rate Adjustment, Proceeding 26852, December 14, 2021, paragraph 57.

[39] Decision 25803-D01-2020: EPCOR Distribution & Transmission Inc., 2019 Annual Transmission Access Charge Deferral Account True-Up, Proceeding 25803, November 20, 2020, paragraph 9.

[40] Under Section 14(3) of the *Electric Utilities Act.*

[41] Decision 27547-D01-2022: Alberta Electric System Operator, 2021 Deferral Account Reconciliation, Proceeding 27547, August 18, 2022.

in a $0.91 million refund to EPCOR's non-direct connect customers. Direct Connect customers will be directly trued up to the dollar on a total refund amount of $0.03 million on a per customer basis.[42]

62. EPCOR's Balancing Pool true-up ensures that its Balancing Pool refund to, or collection from, its customers matches its settlement with the AESO.[43] In 2021, the AESO collected $16.81 million from EPCOR. Due to differences between forecast and actual billing determinants, EPCOR collected $16.88 million from its customers in 2021, necessitating a net refund of $0.07 million.

63. EPCOR calculated carrying costs on outstanding amounts related to the true-up balances in accordance with Rule 023.[44] The rate used was the weighted average Bank of Canada monthly bank rate plus 1.75 per cent and correctly calculated carrying costs on the simple interest basis. EPCOR complied with the Commission's direction from Decision 25803-D01-2020 and excluded the 2021 AESO DAR from the calculation and allocation of carrying costs. The total carrying costs amounted to a $0.09 million collection from customers.

64. EPCOR's application and schedules are consistent with the harmonized framework approved by the Commission in Decision 3334-D01-2015. The Commission finds the amounts comprising the 2021 annual TACDA true-up to be reasonable. The Commission also finds the assignment of the individual components of the 2021 TACDA true-up to rate classes to be consistent with previously approved methodologies and reasonable in the circumstances. Accordingly, the Commission approves a net collection of $1.81 million as set out in Table 3 of this decision.

5.2 Rider J rate and effective period

65. EPCOR proposed to apply the 2021 annual TACDA true-up by way of a Rider J. The true-up of the 2021 Rider J is a collection of $0.10 million. To smooth rates over time and promote rate stability, EPCOR proposed Rider J to be in effect over a 12-month period from January 1, 2023, to December 31, 2023.

66. EPCOR calculated Rider J by summing the 2021 TACDA true-up components and related carrying costs by rate class and divided these amounts by the 2023 forecast billing determinants. The resulting true-up amounts and the proposed Rider J rate are set out in the table below.

42 Exhibit 27653-X0020, TACDA application, Table 4.3-1.

43 Under Section 82 of the *Electric Utilities Act*, each year the Balancing Pool is required to forecast its revenues and expenses to determine any excess or shortfall of funds. Based on this forecast, the Balancing Pool determines an annualized amount that will be refunded to, or collected from, electricity consumers over the year "… so that no profit or loss results, after accounting for the annualized amount under section 82(7) as a revenue or expense of the Balancing Pool." This amount, known as the consumer allocation, applies to all market participants who receive SAS from the AESO and is recovered through Rider F of the AESO tariff. The consumer allocation is based on the amount of electric energy consumed annually. In 2021, the Balancing Pool charged a consumer allocation of $2.20 per megawatt hour (MWh).

44 Rule 023 applies as the lag in the implementation of the refund exceeds 12 months and the revenue amount is sufficient per Section 3(2)(c) to warrant the awarding of carrying costs.

Table 4. True-up amounts and proposed Rider J rate by rate class

Rate class	Total true-up ($)	Rider J rate ($/kWh)
Residential	1,388,093	0.00061
Small General Service	625,184	0.00093
Medium Commercial	2,037,681	0.00214
TOU [Time of Use]	(3,448,025)	(0.00219)
Direct Connects to T.A.	-	-
TOU - Primary	2249,963	0.00039
Customer Specific	1,169,791	0.00191
Customer Specific, Totalized	(353,543)	(0.00162)
Street Lights	114,002	0.00238
Traffic Lights	6,587	0.00160
Lane Lights	10,304	0.00409
Security Lights	5,523	0.00121
Total	**1,805,559**	

Source: Exhibit 27653-X0021, Appendix 1, Schedule 1.0.

67. As shown in Table 4, while the net true-up amount results in a collection, Rider J across individual rate classes will result in either a collection or refund from customer classes. This is due to the relative size of the components of the true-up amounts. In Section 6, the Commission assesses the total bill impact of EPCOR's 2023 rates, including Rider J.

5.3 Inclusion of TACDA true-up in the annual PBR rate adjustment filings

68. In previous decisions, the Commission found that including TACDA true-up applications as part of the annual PBR rate adjustment filings is effective in enhancing regulatory efficiency and reducing administrative burden.

69. In 2023, there will not be an annual PBR rate adjustment filing as the parameters of the PBR3 plans are currently considered in Proceeding 27388. As such, the Commission directs EPCOR to file its 2022 TACDA true-up application as part of a proceeding to establish the January 1, 2024, rates (such as a compliance filing to Proceeding 27388).

70. Subject to the outcome of Proceeding 27388 to establish the parameters of the PBR3 plan (including the issue of when annual rate changes will occur), the Commission directs EPCOR to continue including the annual TACDA true-up in its future annual PBR rate adjustment filings, starting with the 2025 annual PBR rate adjustment filing.

6 2023 rates

71. In this section the Commission must assess how system access service (SAS) charges and DAS charges are collected through distribution rates. These individual components will be recovered by EPCOR's distribution tariff – through its distribution rates, SAS rates and rate riders. The Commission also evaluates the resulting bill impacts.

6.1 System access service rates

72. In its application, EPCOR requested approval of its 2023 SAS rates, to be effective January 1, 2023.[45] EPCOR's proposed 2023 SAS rates reflect its latest forecast of AESO volumes and prices, as of the date of the application. The volume forecast was prepared using its previously approved method; the price forecast relied on the AESO's 2022 Independent System Operator tariff structure and rates as approved in Decision 26980-D01-2021.[46] EPCOR calculated its proposed 2023 SAS rates using the same COS study methodologies and rate structure approved in relation to its 2022 SAS rates in Decision 27153-D01-2022.[47]

73. As a result, the SAS payments forecast for distribution-connected customers increased from $268.5 million included in 2022 PBR rates,[48] to $287.1 million for 2023.[49] This increase in forecast SAS payments reflects an increase of 14.6 per cent in the transmission SAS rate for residential customer, which would result in a two per cent increase to the total bill of a typical residential customer.[50]

74. Additionally EPCOR updated its 2023 Balancing Pool adjustment rider to align with the AESO's Rider F rate. The 2023 AESO Rider F did not change from the previously approved $2.20/MWh approved in Decision 26979-D01-2021.[51]

75. No intervener objected to EPCOR's calculation of its 2023 SAS rates.

76. The Commission has reviewed EPCOR's calculations of its proposed 2023 SAS rates and the underlying assumptions, and finds them to be reasonable and consistent with its past SAS rate proposals. Therefore, the Commission approves the proposed 2023 SAS rates as filed.

6.2 Distribution rates

77. In Section 3 of this decision, the Commission approves the distribution revenue requirement established in Decision 26617-D02-2022.

78. In Section 4 of this decision, the Commission approved individual components of EPCOR's 2023 rates. The Commission also approved a billing determinant forecast,[52] subject to adjustments to the billing determinants for the residential rate class as described in Section 4.2.1. As well, the Commission approved other components of EPCOR's distribution rates: the 2021 TACDA true-up in Section 5 and SAS rates in Section 6.1.

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45 Proceeding 26849, Exhibit 26849-X0001, application, paragraph 63.
46 Decision 26980-D01-2021: Alberta Electric System Operator, 2022 Tariff Update and Rider J Amendment, Proceeding 26980, December 17, 2021.
47 Decision 27153-D01-2022: EPCOR Distribution & Transmission Inc., Compliance Filing to Decision 26836-D01-2021, Proceeding 27153, March 9, 2022.
48 Proceeding 26852, EPCOR 2022 Annual PBR Rate Adjustment Filing and 2020 Annual Transmission Access Charge Deferral Account True-up, Exhibit 26852-X0007.01, Appendix E- 2022 SAS COSS.
49 Exhibit 27653-X0007, Appendix G - 2023 SAS COSS.
50 Exhibit 27653-X0008.02, Appendix H - 2023 Bill Comparison.
51 Decision 26979-D01-2021: Alberta Electric System Operator, 2022 Balancing Pool Consumer Allocation – Rider F, Proceeding 26979, November 24, 2021.
52 Decision 26617-D02-2022, paragraph 31.

79. EPCOR provided bill impact schedules reflecting the 2023 rates, including all components of its distribution tariff that EPCOR proposed to go into effect on January 1, 2023. These are summarized in Table 5.

Table 5. Bill impacts of EPCOR's 2023 rates

Rate class description	Typical bill change – December 2022 vs. January 2023		
	Bill change	Transmission & distribution rates and riders	Total charges (bundled) (Note 1)
	($)	(%)	(%)
Residential	5.83	10.8%	4.5
Small Commercial	13.31	6%	2.4
Medium Commercial	(15.02)	(0.8)	(0.3)
Time of Use- Secondary	908.06	10.1	3.5
Direct Connects	(40.72)	(0.2)	0.0
Time of Use - Primary	(2,363.04)	(7.0)	(2.4)
Street Lights	31,779.09	10.6	3.6
Traffic Lights	1,005.09	4.3	1.5
Lane Lights	2,994.48	22.8	6.9
Security Lights	(18.38)	(17.9)	(13.8)
Customer Specific	(35,744.29)	(18.3)	(5.6)
Customer Specific Totalized	(58,893.51)	(6.6)	(1.7)
Small Commercial Unmetered	6.74	19.5	8.7

Source: Exhibit 27653-X0008.02, Appendix H – 2023 Bill Comparison, Bill Impact – Rates & Riders and Bill Impact – R&R with Energy.
Note 1: All charges, comprising transmission and distribution base rates including riders, retail, energy and local access fee charges.

80. The bill impact on a total bundled bill (i.e., inclusive of distribution, SAS, rate riders, retail, energy and local access fee charges) from EPCOR's proposed 2023 rates is under 10 per cent for all rate classes, except for security lights.

81. The Commission accepts the general principles and methodologies used by EPCOR for calculating its 2023 rates, subject to the update in its forecasting methodology for the residential rate class in post-disposition documents as directed in Section 4.2.1 and updating carrying costs to be consistent with Rule 023.[53] EPCOR is directed to update its 2023 residential rates and its bill comparison in post disposition documents to reflect this change in billing determinants by December 19, 2022. The Commission accepts the bill impacts that result, as shown on Table 5, subject to filing of post disposition documents. This is because the Commission finds that EPCOR has calculated its 2023 rates consistent with the practices and methodologies previously approved by the Commission, including over the course of the 2018-2022 PBR term.

82. Prior to the issuance of this decision, in Disposition 27851-D01-2022[54] the Commission approved the Q1 2023 SAS Deferral Rider S for EPCOR, resulting in further changes to customer bills. However, these changes do not affect the Commission's conclusions in this decision regarding the bill impact of the 2023 rates.

83. For the reasons set out above, the Commission approves EPCOR's 2023 rates on an interim basis as provided in Exhibit 27653-X0011.02, subject to updates filed in post-disposition

[53] EPCOR is to use simple interest instead of compound interest calculations as directed in this decision and in accordance with Rule 023.
[54] Disposition 27851-D01-2022: EPCOR Distribution & Transmission Inc., 2023 Q1 Quarterly AESO DTS Deferral Account Rider, Proceeding 27851, December 12, 2022.

documents as directed in this decision. The 2023 rates are effective January 1, 2023. These rates will remain interim until the approved levels of all remaining placeholders (such as the 2022 actual rate base) have been determined by the Commission. These 2023 rates will be finalized following such approvals, and any required true-up adjustments will be made in accordance with directions subsequently provided by the Commission.

7 Other matters

7.1 Terms and conditions of service and other rate schedules

84. As part of the application, EPCOR provided its 2023 Terms and Conditions for Distribution Access Service (DAS T&Cs),[55] Terms and Conditions for Distribution Connection Service (DCS T&Cs)[56] and Distribution Tariff Policies[57] and Investment Eligibility.[58]

85. EPCOR's DAS T&Cs, Distribution Tariff Policies and Investment Eligibility were approved by the Commission on a final basis in Decision 27018-D01-2022,[59] with the exception of the 2023 MIL rates. The Commission is making no determinations regarding 2023 MILs in this decision. Any decisions regarding 2023 MILs will be issued through Proceeding 27658.

86. EPCOR's DCS T&Cs were approved by the Commission in EPCOR's DAS Phase 2 compliance filing proceeding in Decision 27578-D01-2022.[60]

8 Order

87. It is hereby ordered that:

(1) EPCOR Distribution & Transmission Inc.'s 2023 distribution rates including the options and riders are approved on an interim basis, effective January 1, 2023, subject to EPCOR filing an updated set of schedules reflecting the findings in this decision with the Commission by December 19, 2022. These rates will remain interim pending finalization of all outstanding placeholders.

Dated on December 13, 2022.

55 Exhibit 27653-X0016.
56 Exhibit 27653-X0017.
57 Exhibit 27653-X0018.
58 Exhibit 27653-X0019.
59 Decision 27018-D01-2022, paragraph 89.
60 Decision 27578-D01-2022: EPCOR Distribution & Transmission Inc., Distribution Access Service Phase 2 Compliance Filling, Proceeding 27578, December 12, 2022, paragraph 35.

Alberta Utilities Commission

(original signed by)

Matthew Oliver, CD
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **Company name of counsel or representative**
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI)
Office of the Utilities Consumer Advocate (UCA)   Russ Bell & Associates Inc.

Alberta Utilities Commission
 	
Commission panel
    M. Oliver, CD, Commission Member
 	
Commission staff
    C. Robertshaw
    N. Morter
    F. Alonso
    L. Zhang

Appendix 2 – Summary of Commission directions

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

1. EPCOR is directed to recalculate the Y factor carrying costs amount using simple interest calculations and ensure compound interest is not used in any other interest payment calculations subject to Rule 023, and to file updated schedules reflecting these changes as post-disposition documentation in this proceeding, by December 19, 2022. .. paragraph 19

2. Given the interim nature of the 2023 ECM amount (as explained above), there is no need to update the 2023 rates at this time. The Commission directs EPCOR to true up its 2023 ECM dollar amount, reflecting the methodology approved in this decision, upon the approval of the 2022 actual rate base. .... paragraph 34

3. No party objected to the K-bar true up calculation and the Commission approves the true up as filed with the exception of the correction required to the K-bar carrying cost calculation. The Commission directs EPCOR to recalculate the K-bar true-up carrying costs amount using simple interest calculations and ensure compound interest is not applied in any other carrying cost calculations that are subject to Rule 023. .. paragraph 38

4. The Commission considers that identified variances from forecasts such as those described by EPCOR for 2021 are reasonable. Such occurrences do not generally call into question the predictive value of the methodology used to generate such forecasts. The Commission directs EPCOR to continue to provide information on any variances from forecast to actual billing determinants by rate class and to identify the cause of variances larger than ± five per cent on an annual basis. .... paragraph 45

5. Due to the above, EPCOR's 2023 residential consumption forecast is denied, and EPCOR is directed to use the growth rate average of the last 10 years of actual growth (2012-2021) and apply that to the most recent 2022 residential consumption forecast including updates for September and October actual consumption to obtain the revised 2023 residential consumption forecast. .... paragraph 53

6. This adjustment does not mean that EPCOR should discontinue to use the regression model used for forecasting its billing determinants as approved in Decision 27018-D01-2022. The deviation from the forecast directed by the Commission in this decision is based on its findings regarding the impact of COVID-19 pressures on residential consumption over the 2020 2022 period and only applies for determining the 2023 residential consumption forecast. The Commission directs EPCOR to comment on the regression model accuracy as compared to historic trend and actuals in its application dealing with 2024 distribution rates. .... paragraph 54

7. In 2023, there will not be an annual PBR rate adjustment filing as the parameters of the PBR3 plans are currently considered in Proceeding 27388. As such, the Commission directs EPCOR to file its 2022 TACDA true-up application as part of a proceeding to establish the January 1, 2024, rates (such as a compliance filing to Proceeding 27388). .... paragraph 69

8. Subject to the outcome of Proceeding 27388 to establish the parameters of the PBR3 plan (including the issue of when annual rate changes will occur), the Commission directs

EPCOR to continue including the annual TACDA true-up in its future annual PBR rate adjustment filings, starting with the 2025 annual PBR rate adjustment filing. .... paragraph 70

9. The Commission accepts the general principles and methodologies used by EPCOR for calculating its 2023 rates, subject to the update in its forecasting methodology for the residential rate class in post-disposition documents as directed in Section 4.2.1 and updating carrying costs to be consistent with Rule 023. EPCOR is directed to update its 2023 residential rates and its bill comparison in post disposition documents to reflect this change in billing determinants by December 19, 2022. The Commission accepts the bill impacts that result, as shown on Table 5, subject to filing of post disposition documents. This is because the Commission finds that EPCOR has calculated its 2023 rates consistent with the practices and methodologies previously approved by the Commission, including over the course of the 2018-2022 PBR term.................................... paragraph 81

Appendix 3 – 2023 Balancing Pool Rider G

Appendix 3 - 2023
Balancing Pool Ride

(consists of 1 page)

Appendix 4 – 2023 SAS rates

(return to text)

Appendix 4 - 2023
SAS rates

(consists of 27 pages)

Appendix 5 – SAS true-up Rider J

Appendix 5 - SAS
true-up Rider J

(consists of 1 page)

TEMPORARY ADJUSTMENT

Rider G - Balancing Pool Rider

Effective: January 1, 2023

- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption effective January 1, 2023 to December 31, 2023.

- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Rate Schedule	Energy Charge	Demand Charge per KW or KVA per Day	OSS Charge	Operating Reserve
SAS-R	$0.00228	N/A	N/A	N/A
SAS-SC	$0.00228	N/A	N/A	N/A
SAS-MC	$0.00228	N/A	N/A	N/A
SAS-TOU	$0.00226	N/A	N/A	N/A
SAS-DC	$0.00000	N/A	N/A	N/A
SAS-TOUP	$0.00223	N/A	N/A	N/A
SAS-CS	$0.00221	N/A	N/A	N/A
SAS CST	$0.00220	N/A	N/A	N/A
SAS-SL	$0.00228	N/A	N/A	N/A
SAS-TL	$0.00228	N/A	N/A	N/A
SAS-LL	$0.00228	N/A	N/A	N/A
SAS-SEL	$0.00228	N/A	N/A	N/A
SAS-DGEN	N/A	N/A	N/A	N/A

Note: Rider G does not apply to Rider LAF and Rider J.

DT – Schedule A

Transmission Access Service Tariff
Effective January 1, 2023

Table of Contents

RESIDENTIAL SERVICE
(2023 INTERIM RATE)

Price Schedule SAS-R

Effective: January 1, 2023

- For System Access Service for all Points of Service throughout the territory served by the Company.
- For single-phase service at secondary voltage through a single meter.
- For normal use by a single and separate household.
- Not applicable to any commercial or industrial use.

Price

- The charge for service in any one billing day is the Energy Charge, determined for each individual Point of Service.

	Energy Charge (per kWh)
Transmission	SAS-R1* $0.03966

- The minimum daily charge is the Energy Charge.

Application

1) **Price Adjustments** - the following price adjustments (riders) may apply:

Local Access Fees (Rider LAF) – See Note
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

Commercial/Industrial <50 kVA
(2023 INTERIM RATE)

Price Schedule SAS-SC

Effective: January 1, 2023

- For System Access Service for all Points of Service that have a normal maximum demand of less than 50 kVA with single or three-phase electric service at secondary voltage, throughout the territory served by the Company. These services will have energy meters or will have energy consumption on an estimated basis. This rate is also applicable to all sites for which no other rate is applicable.

Price

- Charges for service in any one billing day shall be the Energy Charge, determined for each individual Point of Service:

	Energy Charge (per kWh)
Transmission	SAS-SC1* $0.03924

- The minimum daily charge is the Energy Charge.

Application

1) **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment

2) **Price Adjustments** - the following price adjustments (riders) may apply:

   Local Access Fees (Rider LAF) – See Note
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

Commercial/Industrial 50 kVA to <150 kVA
(2023 INTERIM RATE)

Price Schedule SAS-MC

Effective: January 1, 2023

- For System Access Service for all Points of Service that have a normal maximum demand of greater than or equal to 50 kVA and less than 150 kVA, with single or three-phase electric service at secondary voltage, throughout the territory served by the Company. These services will have demand meters

Price

- Charges for service in any one billing day shall be the sum of the Capacity Charge, Energy Charge and Demand Charge, determined for each individual Point of Service:

	Capacity Charge (per kVA of billing demand per Day**)**	**Energy Charge** (per kWh)	**Demand Charge** (per kVA of peak metered demand per Day**)**
Transmission	SAS-MC1* $0.09669	SAS-MC2* $0.00834	SAS-MC3* $0.19591

- The billing demand may be estimated or measured and will be the greater of the following:

  (a) the highest metered demand during the billing period;
  (b) 90% of the highest metered demand in the twelve month period including and ending with the billing period;
  (c) the estimated demand;
  (d) the contract demand;
  (e) 5 kVA.

- The Peak Metered Demand is the highest metered demand in the billing period.

- The minimum daily charge is the sum of the Capacity Charge, Energy Charge and Demand Charge.

Application

1) **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment

2) **Price Adjustments** - the following price adjustments (riders) may apply:
   Local Access Fees (Rider LAF) – See Note
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.
* Refer to the values associated with the Cell References in the Attached Table 3.

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

Commercial/Industrial 150 kVA to <5,000 kVA
Distribution-Connected
(2023 INTERIM RATE)

Price Schedule SAS-TOU

Effective: January 1, 2023

- For System Access Services, single or three-phase, that have a normal maximum demand of greater than or equal to 150 kVA and less than 5,000 kVA, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System. This rate is applicable to all sites that are served at the secondary voltage of the transformer, normally with a delivery voltage of below 1,000 volts.

- The Point of Service must be equipped with interval data metering.

Price

- Charges for service in any one billing day shall be the sum of the Energy Charge, Capacity Charge, OSS Charge, Operating Reserve Charges and Demand Charge, determined for each individual Point of Service:

	Energy Charge (per kWh)	**Capacity Charge** (per kW of billing demand per Day**)**	**OSS Charge** (per kW per Day)	**Operating Reserve** (% x kWh delivered during each hour x Applicable Pool Price during each hour)	**Demand Charge** (per kW of peak metered demand per Day**)**
Transmission	SAS-TOU1* $0.00216	SAS-TOU2* $0.14078	SAS-TOU3* $0.00059	SAS-TOU4* 5.96%	SAS-TOU5* $0.26891

- **Billing demand** shall be the higher of:

  (a) The highest metered demand during the billing period;
  (b) 85% of the highest metered demand in the 12-month period including and ending with the billing period;
  (c) the estimated demand;
  (d) the Transmission Contract Demand (TCD);
  (e) 50 kilowatts.

- The Peak Metered Demand is the highest metered demand in the billing period.

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

Commercial/Industrial 150 kVA to <5,000 kVA
Distribution Connected
(2023 INTERIM RATE)

Price Schedule SAS-TOU (Continued) ***Effective: January 1, 2023***

Application

1) **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment

2) **Price Adjustments** - the following price adjustments (riders) may apply:

Local Access Fees (Rider LAF) – See Note
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

Primary Commercial/Industrial 150 kVA to <5,000 kVA
Distribution Connected
(2023 INTERIM RATE)

Price Schedule SAS-TOUP — *Effective: January 1, 2023*

- For System Access Service, single or three-phase, that have a normal maximum demand of greater than or equal to 150 kVA and less than 5,000 kVA, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System. This rate is applicable to all sites that are served at the primary voltage of the transformer, normally with a delivery voltage of over 1,000 volts.

- The Point of Service must be equipped with interval data metering.

Price

- Charges for service in any one billing day shall be the sum of the Energy Charge, Capacity Charge, OSS Charge, Operating Reserve Charges and Demand Charge determined for each individual Point of Service:

	Energy Charge (per kWh)	**Capacity Charge** (per kW of billing demand per Day**)**	**OSS Charge** (per kW per Day)	**Operating Reserve** (% x kWh delivered during each hour x Applicable Pool Price during each hour)	**Demand Charge** (per kW of peak metered demand per Day**)**
Transmission	SAS-TOUP1* $0.00213	SAS-TOUP2* $0.12318	SAS-TOUP3* $0.00051	SAS-TOUP4* 5.89%	SAS-TOUP5* $0.25430

- **Billing demand** shall be the higher of:

  a) The highest metered demand during the billing period;
  b) 85% of the highest metered demand in the 12-month period including and ending with the billing period;
  c) the estimated demand;
  d) the Transmission Contract Demand (TCD);
  e) 50 kilowatts.

- The Peak Metered Demand is the highest metered demand in the billing period.

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

Primary Commercial/Industrial 150 kVA to <5,000 kVA
Distribution Connected
(2023 INTERIM RATE)

Price Schedule SAS-TOUP (Continued) — *Effective: January 1, 2023*

Application

1) **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment

2) **Price Adjustments** - the following price adjustments (riders) may apply:

   Local Access Fees (Rider LAF) - Note
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

Commercial/Industrial Greater than 5,000 kVA
Distribution-Connected
(2023 INTERIM RATE)

Price Schedule SAS-CS *Effective: January 1, 2023*

- For System Access Service, single or three-phase, that have a maximum demand of greater than or equal to 5,000 kVA in the previous year, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System. This rate is also applicable to new sites that forecast to have a normal maximum demand of greater than or equal to 5,000 kVA. The Point of Service must be equipped with interval data metering.

- Each new site under this rate is required to enter into an Electric Service Agreement with EPCOR SYSTEM.

Price

- Charges for service in any one billing day shall be the sum of the Energy Charge, Capacity Charge, OSS Charge, Operating Reserve Charges and Demand Charge, determined for each individual Point of Service:

	Energy Charge (per kWh)	**Capacity Charge** (per kW of billing demand per Day**)**	**OSS Charge** (per kW per Day)	**Operating Reserve** (% x kWh delivered during each hour x Applicable Pool Price during each hour)	**Demand Charge** (per kW of peak metered demand per Day**)**
Transmission	SAS-CS1* $0.00211	SAS-CS2* $0.12174	SAS-CS3* $0.00051	SAS-CS4* 5.83%	SAS-CS5* $0.27893

- **Billing demand** shall be the higher of:

  a) The highest metered demand during the billing period;
  b) 90% of the highest metered demand in the 24-month period including and ending with the billing period;
  c) the estimated demand;
  d) the Transmission Contract Demand (TCD);
  e) 50 kilowatts.

- The Peak Metered Demand is the highest metered demand in the billing period.

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Commercial/Industrial Greater than 5,000 kVA
Distribution-Connected
(2023 INTERIM RATE)

Price Schedule SAS-CS (Continued)

Application

1) **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment

2) **Price Adjustments** - the following price adjustments (riders) may apply:
   Local Access Fees (Rider LAF) – See Note
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

Commercial/Industrial Greater than 5,000 kVA Totalized
Distribution-Connected
(2023 INTERIM RATE)

Price Schedule SAS-CST — *Effective: January 1, 2023*

- For System Access Service, single or three-phase, that have a totalized maximum demand of greater than or equal to 5,000 kVA in the previous year, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System. This rate is also applicable to new sites that forecast to have a normal totalized maximum demand of greater than or equal to 5,000 kVA. The Point of Service must be equipped with interval data metering.

- Each new site under this rate is required to enter into an Electric Service Agreement with EPCOR SYSTEM.

Price

- Charges for service in any one billing day shall be the sum of the Capacity Charge, Energy Charge, Demand Charge, OSS Charge, Fixed POD Daily Charge and Operating Reserve Charges, determined for each individual Point of Service:

	Capacity Charge (per kW of billing demand per Day)	**Energy Charge** (per kWh)	**Operating Reserve** (% x kWh delivered during each hour x Applicable Pool Price during each hour)	**OSS Charge** (per kW per Day)	**Fixed Point of Delivery Daily Charge**	**Demand Charge** (per kW of peak metered demand per Day)
Transmission	SAS-CST3* $0.15682	SAS-CST4* $0.00212	SAS-CST5* 5.86%	SAS-CST6* $0.00065	SAS-CST7* $371.62	SAS-CST8* $0.25787

- **Billing demand** shall be the higher of:

  a) The highest metered demand during the billing period;
  b) 90% of the highest metered demand in the 24-month period including and ending with the billing period;
  c) the estimated demand;
  d) 90% the Transmission Contract Demand (TCD);
  e) 50 kilowatts.

- The Peak Metered Demand is the highest metered demand in the billing period.

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Commercial/Industrial Greater than 5,000 kVA Totalized
Distribution-Connected
(2023 INTERIM RATE)

Price Schedule SAS-CST (Continued)

Application

1) **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment

2) **Price Adjustments** - the following price adjustments (riders) may apply:

   Local Access Fees (Rider LAF) – See Note
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

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Commercial/Industrial Greater than 5,000 kVA Totalized
Distribution-Connected
(2023 INTERIM RATE)

Price Schedule SAS-CST21 *Effective: January 1, 2023*

- For System Access Service, single or three-phase, that have a totalized maximum demand of greater than or equal to 5,000 kVA in the previous year, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System. This rate is also applicable to new sites that forecast to have a normal totalized maximum demand of greater than or equal to 5,000 kVA. The Point of Service must be equipped with interval data metering.

- Each new site under this rate is required to enter into an Electric Service Agreement with EPCOR SYSTEM.

Price

- Charges for service in any one billing day shall be the sum of the Capacity Charge, Energy Charge, Demand Charge, OSS Charge, Fixed POD Daily Charge and Operating Reserve Charges, determined for each individual Point of Service:

	Capacity Charge (per kW of billing demand per Day**)**	**Energy Charge** (per kWh)	**Operating Reserve** (% x kWh delivered during each hour x Applicable Pool Price during each hour)	**OSS Charge** (per kW per Day)	**Fixed Point of Delivery Daily Charge**	**Demand Charge** (per kW of peak metered demand per Day**)**
Transmission	SAS-CST21-3* $0.16889	SAS-CST21-4* $0.21170	SAS-CST21-5* 5.85%	SAS-CST21-6* $0.00074	SAS-CST21-7* $48.53	SAS-CST21-8* $0.30933

- **Billing demand** shall be the higher of:

  a) The highest metered demand during the billing period;
  b) 90% of the highest metered demand in the 24-month period including and ending with the billing period;
  c) the estimated demand;
  d) 90% of the Transmission Contract Demand (TCD);
  e) 50 kilowatts.

- The Peak Metered Demand is the highest metered demand in the billing period.

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

Commercial/Industrial Greater than 5,000 kVA Totalized
Distribution-Connected
(2023 INTERIM RATE)

Price Schedule SAS-CST21 (Continued)

Application

1) **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment

2) **Price Adjustments** - the following price adjustments (riders) may apply:

   Local Access Fees (Rider LAF) – See Note
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

Direct Transmission-Connected
(2023 INTERIM RATE)

Price Schedule SAS-DC

Effective: January 1, 2023

- For System Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System, that are directly connected to a transmission substation, and do not make any use of System facilities owned by EPCOR System.
- The Point of Service must be equipped with interval data metering.

Price

- Charges for service in any one billing day shall be the sum of the Energy Charge, Demand Charge, OSS Charge and Operating Reserve Charges, determined for each individual Point of Service:

Transmission	The applicable rate(s) of the Alberta Electric System Operator Tariff

- **Total charges from the AESO for each Point of Delivery applicable to sites on this rate will be flowed through to such sites.**

Application

1) **Price Adjustments** - the following price adjustments (riders) may apply:

   Local Access Fees (Rider LAF) – See Note
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

GENERATOR INTERCONNECTION
Distribution-Connected
(2023 INTERIM RATE)

Price Schedule SAS-DGEN ***Effective: January 1, 2023***

- For Points of Service served by the Company from the Alberta Interconnected System, with on-site generating equipment connected to the System, which may be used to supply load at the same site.
- For interconnection of the generator to the Distribution System
- To charge Generators if the Point of Delivery attracts STS charges from the AESO
- The Point of Service must be equipped with bi-directional interval data metering, for both supply and demand, the cost of which will be in addition to the charges under this rate.

Price

- Charges for service in any one billing day shall be the sum of the STS charges from the AESO:

Capital Recovery Charges:

- The cost of the Incremental Interconnection Facilities will be determined as set out in Section 9.4 of the Terms and Conditions for System Service Connections. The total amount will be collected from the customer in accordance with Section 9.5 of the Terms and Conditions for System Service Connections. A contract will be arranged between the customer and the Company, specifying the contract term and the monthly amount, which will be calculated using the Company's Rate of Return and Depreciation in effect at the commencement of the contract term.
- The Generating customer will be required to pay all replacement costs for incremental facilities as per Section 9.4 of the Terms and Conditions for System Service Connections.

Application

1) **Price Adjustments** - the following price adjustments (riders) may apply:

    Local Access Fees (Rider LAF) – See Note
    Temporary Adjustment (Rider G)
    Interim Adjustment (Rider J)
    Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

STREET LIGHTING SERVICE
(2023 INTERIM RATE)

Price Schedule SAS-SL

Effective: January 1, 2023

- To the Retailer for services owned by the City of Edmonton for Street Lighting Service

Price

- Charges for service in any one billing month are the sum of the Demand Charges.

	Demand Charge (per kW per Day)
Transmission	SAS-SL1* $0.23386

- Billing demand for the Transmission charges shall be 90% of the highest metered demand in the 12-month period including and ending with the billing period.

Application

1) **Price Adjustments** – the following price adjustments (riders) may apply:

   Local Access Fees (Rider LAF) – See note
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

Traffic Control
(2023 INTERIM RATE)

Price Schedule SAS-TL *Effective: January 1, 2023*

- For services owned by the City of Edmonton for Traffic Lights and other Traffic Control Service.

Price

- Charges for service in any one billing month are the sum of the Demand Charges.

	Demand Charge (per kW per Day)
Transmission	SAS-TL1* $0.83215

- Billing demand for the Transmission charges shall be 90% of the highest metered demand in the 12-month period including and ending with the billing period.

Application

1) **Price Adjustments** – the following price adjustments (riders) may apply:

Local Access Fees (Rider LAF) – See Note
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

Security Lighting Service
(2023 INTERIM RATE)

Price Schedule SAS-SEL — *Effective: January 1, 2023*

- For existing unmetered Security Light Service. This rate is not available to new services.

Price

- Charges for service in any one billing month are the sum of the Demand Charges, determined for each individual Point of Service.

	Demand Charge (per kW per Day)
Transmission	SAS-SEL1* $0.22408

- Billing demand for the Transmission charges shall be 90% of the highest metered demand in the 12-month period including and ending with the billing period.

Application

1) **Price Adjustments** – the following price adjustments (riders) may apply:

Local Access Fees (Rider LAF) – See Note
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

Lane Lighting Service
(2023 INTERIM RATE)

Price Schedule SAS-LL — *Effective: January 1, 2023*

- For the services owned by the City of Edmonton for Lane Lights.

Price

- Charges for service in any one billing month are the sum of the Demand Charges.

	Demand Charge (per kW per Day)
Transmission	SAS-LL1* $0.24553

- Billing demand for the Transmission charges shall be 90% of the highest metered demand in the 12-month period including and ending with the billing period.

Application

1) **Price Adjustments** – the following price adjustments (riders) may apply:

Local Access Fees (Rider LAF)- See Note
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Short Term Adjustment (Rider K)

Note: The Local Access Fee (LAF) is a surcharge imposed by the City of Edmonton and is not approved by the Alberta Utilities Commission. The LAF applies to all sites within the City of Edmonton.

* Refer to the values associated with the Cell References in the Attached Table 3.

TEMPORARY ADJUSTMENT

Rider G - Balancing Pool Rider

Effective: January 1, 2023

- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption.

- Current Rider G rates are available on EPCOR's website: https://www.epcor.com/products-services/power/rates-tariffs-fees/Pages/power-tariffs-terms-and-conditions-edmonton.aspx

Rate Schedule	Energy Charge	Demand Charge per KW or KVA per Day	OSS Charge	Operating Reserve
SAS-R	N/A	N/A	N/A	N/A
SAS-SC	N/A	N/A	N/A	N/A
SAS-MC	N/A	N/A	N/A	N/A
SAS-TOU	N/A	N/A	N/A	N/A
SAS-TOUP	N/A	N/A	N/A	N/A
SAS-CS	N/A	N/A	N/A	N/A
SAS CST	N/A	N/A	N/A	N/A
SAS-DC	N/A	N/A	N/A	N/A
SAS-DGEN	N/A	N/A	N/A	N/A
SAS-SL	N/A	N/A	N/A	N/A
SAS-TL	N/A	N/A	N/A	N/A
SAS-SEL	N/A	N/A	N/A	N/A
SAS-LL	N/A	N/A	N/A	N/A

Note: Rider G does not apply to Rider LAF and Rider J.

INTERIM ADJUSTMENT

Rider J - SAS True-Up Rider

Effective: January 1, 2023

- Applies to all electric service throughout the territory served by the Company when a charge or refund is approved by the AUC.
- Current Rider J rates are available on EPCOR's website: https://www.epcor.com/products-services/power/rates-tariffs-fees/Pages/power-tariffs-terms-and-conditions-edmonton.aspx

Rate Schedule	Energy Charge	Demand Charge per KW or KVA per Day	OSS Charge	Operating Reserve
SAS-R	N/A	N/A	N/A	N/A
SAS-SC	N/A	N/A	N/A	N/A
SAS-MC	N/A	N/A	N/A	N/A
SAS-TOU	N/A	N/A	N/A	N/A
SAS-TOUP	N/A	N/A	N/A	N/A
SAS-CS	N/A	N/A	N/A	N/A
SAS-CST	N/A	N/A	N/A	N/A
SAS-DC	N/A	N/A	N/A	N/A
SAS-DGEN	N/A	N/A	N/A	N/A
SAS-SL	N/A	N/A	N/A	N/A
SAS-TL	N/A	N/A	N/A	N/A
SAS-SEL	N/A	N/A	N/A	N/A
SAS-LL	N/A	N/A	N/A	N/A

SHORT-TERM ADJUSTMENT

Rider K - Transmission Charge Deferral Account True-Up Rider *Effective: January 1, 2023*

- Applies to all electric service throughout the territory served by the Company when a charge or refund is approved by the AUC.
- Current Rider K rates are available on EPCOR's website: https://www.epcor.com/products-services/power/rates-tariffs-fees/Pages/power-tariffs-terms-and-conditions-edmonton.aspx

Rate Schedule	Energy Charge	Demand Charge per KW or KVA per Day	OSS Charge	Operating Reserve
SAS-R	-	N/A	N/A	N/A
SAS-SC	-	N/A	N/A	N/A
SAS-MC	-	N/A	N/A	N/A
SAS-TOU	-	N/A	N/A	N/A
SAS-TOUP	-	N/A	N/A	N/A
SAS-CS	-	N/A	N/A	N/A
SAS-CST	-	N/A	N/A	N/A
SAS-DC	-	N/A	N/A	N/A
SAS-DGEN	-	N/A	N/A	N/A
SAS-SL	-	N/A	N/A	N/A
SAS-TL	-	N/A	N/A	N/A
SAS-SEL	-	N/A	N/A	N/A
SAS-LL	-	N/A	N/A	N/A

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Table 3: EDTI's 2023 System Access Service Rate Schedules
(2023 INTERIM RATE)

Rate Class	Cell Reference	Value	Description
Residential	SAS-R1	$0.03966	/ kWh of Energy Charge
Commercial/ Industrial Service <50 kVA	SAS-SC1	$0.03924	/ kWh of Energy Charge
Commercial/ Industrial Service 50 kVA to Less Than 150 kVA	SAS-MC1	$0.09669	/kVA/day of Capacity Charge
Commercial/ Industrial Service 50 kVA to Less Than 150 kVA	SAS-MC2	$0.00834	/ kWh of Energy Charge
Commercial/ Industrial Service 50 kVA to Less Than 150 kVA	SAS-MC3	$0.19591	/kVA/day of Demand Charge
150 to 5000 kVA (Secondary)	SAS-TOU1	$0.00216	/ kWh of Energy Charge
150 to 5000 kVA (Secondary)	SAS-TOU2	$0.14078	/kW/day of Capacity Charge
150 to 5000 kVA (Secondary)	SAS-TOU3	$0.00059	/kW/day of Other System Support Charge
150 to 5000 kVA (Secondary)	SAS-TOU4	5.96%	Operating Reserve Charge (Total Energy x OR% x Pool Price)
151 to 5000 kVA (Secondary)	SAS-TOU5	$0.26891	/kW/day of Demand Charge
150 to 5000 kVA (Primary)	SAS-TOUP1	$0.00213	/ kWh of Energy Charge
150 to 5000 kVA (Primary)	SAS-TOUP2	$0.12318	/kW/day of Capacity Charge
150 to 5000 kVA (Primary)	SAS-TOUP3	$0.00051	/kW/day of Other System Support Charge
150 to 5000 kVA (Primary)	SAS-TOUP4	5.89%	Operating Reserve Charge (Total Energy x OR% x Pool Price)
151 to 5000 kVA (Primary)	SAS-TOUP5	$0.25430	/kW/day of Demand Charge
> 5000 kVA	SAS-CS1	$0.00211	/ kWh of Energy Charge
> 5000 kVA	SAS-CS2	$0.12174	/kW/day of Capacity Charge
> 5000 kVA	SAS-CS3	$0.00051	/kW/day of Other System Support Charge
> 5000 kVA	SAS-CS4	5.83%	Operating Reserve Charge (Total Energy x OR% x Pool Price)
> 5000 kVA	SAS-CS5	$0.27893	/kW/day of Demand Charge
CST	SAS-CST3	$0.15682	/kW/day of Capacity Charge
CST	SAS-CST4	$0.00212	/ kWh of Energy Charge
CST	SAS-CST5	5.86%	Operating Reserve Charge (Total Energy x OR% x Pool Price)
CST	SAS-CST6	$0.00065	/kW/day of Other System Support Charge
CST	SAS-CST7	$371.62	Daily Charge Mulitplied by POD Percentage
CST	SAS-CST8	$0.25787	/kW/day of Demand Charge
CST21	SAS-CST21-3	$0.16889	/kW/day of Capacity Charge
CST21	SAS-CST21-4	$0.21170	/ kWh of Energy Charge
CST21	SAS-CST21-5	5.85%	Operating Reserve Charge (Total Energy x OR% x Pool Price)
CST21	SAS-CST21-6	$0.00074	/kW/day of Other System Support Charge
CST21	SAS-CST21-7	$48.53	Daily Charge Mulitplied by POD Percentage

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Rate Class	Cell Reference	Value	Description
CST21	SAS-CST21-8	$0.30933	/kW/day of Demand Charge
Direct Connects to AESO	SAS-DC1	Flowthrough	/ kWh of Energy Charge
Direct Connects to AESO	SAS-DC2	Flowthrough	/kW/day of Demand Charge
Direct Connects to AESO	SAS-DC3	Flowthrough	/kW/day of Other System Support Charge
Direct Connects to AESO	SAS-DC4	Flowthrough	Pool Price Charge (Total Energy)
Direct Connects to AESO	SAS-DC5	Flowthrough	Fixed Point of Delivery Daily Charge Multiplied by applicable Substation Fraction
Photo Eye (Street Lights)	SAS-SL1	$0.23386	/kW/day of Demand Charge
Continuous Operating Load	SAS-TL1	$0.83215	/kW/day of Demand Charge
Photo Eye (Security Lights)	SAS-SEL1	$0.22408	/kW/day of Demand Charge
Photo Eye (Lane Lights)	SAS-LL1	$0.24553	/kW/day of Demand Charge

Table 4: EDTI's 2023 Customer Specific Loss Factor and Operating Reserve Percentage

Rate Class	Cell Reference	CS Loss Factor	SAS-CS4	Description
> 5000 kW - Primary	CS20	0.16%	5.82%	Specific Distribution Loss Factor - CS20
> 5000 kW - Primary	CS21	0.35%	5.83%	Specific Distribution Loss Factor - CS21
> 5000 kW - Primary	CS22	1.35%	5.89%	Specific Distribution Loss Factor - CS22
> 5000 kW - Primary	CS23	0.18%	5.82%	Specific Distribution Loss Factor - CS23
> 5000 kW - Primary	CS24	0.09%	5.82%	Specific Distribution Loss Factor - CS24
> 5000 kW - Primary	CS25	0.20%	5.82%	Specific Distribution Loss Factor - CS25
> 5000 kW - Primary	CS26	1.44%	5.90%	Specific Distribution Loss Factor - CS26
> 5000 kW - Primary	CS27	0.20%	5.82%	Specific Distribution Loss Factor - CS27
> 5000 kW - Primary	CS28	0.43%	5.84%	Specific Distribution Loss Factor - CS28
> 5000 kW - Primary	CS29	0.38%	5.83%	Specific Distribution Loss Factor - CS29
> 5000 kW - Primary	CS30	0.01%	5.81%	Specific Distribution Loss Factor - CS30
> 5000 kW - Primary	CS31	0.18%	5.82%	Specific Distribution Loss Factor - CS31
> 5000 kW - Primary	CS32	0.19%	5.82%	Specific Distribution Loss Factor - CS32
> 5000 kW - Primary	CS33	1.37%	5.89%	Specific Distribution Loss Factor - CS33
> 5000 kW - Primary	CS34	0.10%	5.86%	Specific Distribution Loss Factor - CS34
> 5000 kW - Primary	CS35	0.30%	5.83%	Specific Distribution Loss Factor - CS35
> 5000 kW - Primary	CS37	0.00%	5.81%	Specific Distribution Loss Factor - CS37
> 5000 kW - Primary	CS38	0.12%	5.82%	Specific Distribution Loss Factor - CS38
> 5000 kW - Primary	CS39	0.72%	5.85%	Specific Distribution Loss Factor - CS39
> 5000 kW - Primary	CS40	1.27%	5.89%	Specific Distribution Loss Factor - CS40
> 5000 kW - Primary	CS42	0.57%	5.85%	Specific Distribution Loss Factor - CS42
> 5000 kW - Primary	CS43	0.51%	5.84%	Specific Distribution Loss Factor - CS43

EPCOR Distribution & Transmission Inc.'s Terms and Conditions for Distribution Access Service and Terms and Conditions for Distribution Service Connections apply to all retailers and customers provided with Distribution Access Services and/or System Access Service by EPCOR Distribution & Transmission Inc. Both sets of Terms and Conditions are available at EPCOR System offices during normal working hours or on the website www.epcor.ca.

> 5000 kW - Primary	CS44	0.47%	5.84%	Specific Distribution Loss Factor - CS44
> 5000 kW - Primary	CS46	0.57%	5.85%	Specific Distribution Loss Factor - CS46
> 5000 kW - Primary	CS48	0.93%	5.87%	Specific Distribution Loss Factor - CS48
> 5000 kW - Primary	CS49	1.04%	5.87%	Specific Distribution Loss Factor - CS49

EPCOR Distribution & Transmission Inc.

Effective: January 1, 2023

INTERIM ADJUSTMENT

Rider J - SAS True-Up Rider — ***Effective: January 1, 2023***

- Applies to all electric service throughout the territory served by the Company when a charge or refund is approved by the AUC. Effective January 1, 2023 to December 31, 2023.

Rate Schedule	Energy Charge	Demand Charge per KW or KVA per Day	OSS Charge	Operating Reserve
SAS-R	$0.00061	N/A	N/A	N/A
SAS-SC	$0.00093	N/A	N/A	N/A
SAS-MC	$0.00214	N/A	N/A	N/A
SAS-TOU	$(0.00219)	N/A	N/A	N/A
SAS-TOUP	$0.00039	N/A	N/A	N/A
SAS-CS	$0.00191	N/A	N/A	N/A
SAS-CST	$(0.00162)	N/A	N/A	N/A
SAS-DC	$0.00000	N/A	N/A	N/A
SAS-DGEN	N/A	N/A	N/A	N/A
SAS-SL	$0.00238	N/A	N/A	N/A
SAS-TL	$0.00160	N/A	N/A	N/A
SAS-LL	$0.00409	N/A	N/A	N/A
SAS-SEL	$0.00121	N/A	N/A	N/A