Decision **26836-D01-2021**

Alberta Utilities Commission

EPCOR Distribution & Transmission Inc.

2022 System Access Service Phase 2 Application

November 29, 2021

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Contents

List of figures

List of tables

EPCOR Distribution & Transmission Inc. **Decision 26836-D01-2021**
2022 System Access Service Phase 2 Application **Proceeding 26836**

1 Decision summary

1. In this decision, the Alberta Utilities Commission approves EPCOR Distribution & Transmission Inc.'s application to modify its 2022 system access service (SAS) rate design to include a monthly non-coincident peak (NCP) metered demand charge for several of its commercial and industrial customer rate classes. The Commission directs EPCOR to submit a compliance filing to this decision by February 15, 2022, to incorporate the latest available information in its April 1, 2022, SAS rates before they are effected. The Commission also directs EPCOR to examine its how its remaining demand ratchets and minimum demand amounts are set in its next Phase 2 application.

2 Introduction

2. EPCOR requires revenue to pay for the costs it incurs in operating its electric distribution business, as well as the costs and charges imposed on it for accessing the electric transmission system. EPCOR obtains this revenue from its distribution tariff. A distribution tariff specifies the rates charged to each customer rate class for service as well as the terms and conditions of service. EPCOR must apply to the Commission for approval of its distribution tariff.

3. Setting customer rates in a distribution tariff generally involves two phases, each requiring Commission approval:

- In Phase 1, a utility calculates its total annual revenue requirement, which includes transmission and distribution costs. Transmission costs, which are sometimes also referred to as system access service, or SAS, costs, are what EPCOR must pay, on behalf of its customers, to the Alberta Electric System Operator (AESO) for transmission service. Distribution costs are the costs that EPCOR incurs to construct and operate its electric distribution system.

- In Phase 2, the utility apportions its annual revenue requirement approved in Phase 1 among its customers. Generally, this is broken up into two steps. First, the utility allocates the costs to various groups of customers (referred to as customer rate classes). Then it uses those cost allocations to inform how to design customers rates.

4. EPCOR applied to the Commission to update its Phase 2 rate design with respect to how it collects transmission SAS costs. The update seeks to include a monthly NCP metered demand charge for the following customer rate classes:

- Medium Commercial
- Time of Use
- Time of Use – Primary
- Customer Specific
- Customer Specific – Totalized

5. A demand charge is a generic term used to describe a way in which customers are billed. Distribution utilities can bill customers based on a fixed charge (i.e., billed based on the number of days the customer is connected to the system, as $/day), a volumetric charge (i.e., based on the total energy, or kilowatt (kW) hours, consumed by the customer, billed as $/kW hour), a demand charge (i.e., based on the peak level of consumption over a certain time period, billed as $/kW or $/kilovolt ampere (kVA)), or a combination of these charges, depending on the customer class and metering infrastructure installed on the system. Other, less common types of charges are also used in some circumstances.

6. Demand charges can be calculated in a number of different ways, depending on how the peak level of consumption is defined and what the time period considered is. EPCOR applied to include a monthly NCP metered demand charge in its SAS rate design. Monthly NCP means that a customer's peak demand is determined relative to their own usage for the month billed, regardless of other customers' demand on the system at that time (i.e., not coincident with the system peak). For ease of reference, the Commission will refer to EPCOR's applied-for monthly NCP metered demand charge simply as EPCOR's proposed NCP demand charge.[1]

7. Demand charges are typically levied based on a customer's actual demand for the billing period, and may be subject to certain billing minimums. Common billing minimums include a customer's contracted demand, a specified rate class minimum demand, and a ratchet provision. A ratchet is a billing minimum, and is typically calculated as some percentage of the customer's highest demand in the last 12 or 24 months. A customer's demand in a billing period is then calculated as the greater of: (i) their highest actual metered demand in the month; and (ii) the billing minimums, if such are applied.

8. The current transmission rate design for the rate classes affected by EPCOR's proposal includes a single demand charge. The demand measurement used for the charge is calculated as the highest of the customer's actual demand in the billing period and billing minimums, which include a ratchet, the customer's contract demand, and specified rate class minimum demands.[2]

9. EPCOR's proposed NCP demand charge does not include billing minimums. This means that the demand charge is not affected by the customer's historical usage and can be more variable from month to month, and is calculated entirely based on the customer's highest demand in the month.[3]

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[1] EPCOR's application also refers to this as an unratcheted, metered demand charge.

[2] For example, for EPCOR's medium commercial rate class, 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 per cent of the highest metered demand in the 12 month period including and ending with the billing period; (c) the estimated demand; (d) the contract demand; and (e) 5 kVA. See Exhibit 26836-X0007.

[3] See for example Exhibit 26836-X0006, Schedule A, Transmission Access Service Tariff, page 3, Price Schedule SAS-MC, Peak Metered Demand.

10. EPCOR confirmed that its proposal to include an NCP demand charge would not change the total amount of revenue EPCOR would collect, nor the methodology used to allocate costs to the affected customer rate classes. It would only change how those costs are billed to the customers in the affected rate classes.[4]

11. EPCOR proposed to implement this rate design change for its 2022 SAS rates effective April 1, 2022.

12. The Office of the Utilities Consumer Advocate and the Canada West Ski Areas Association intervened in the proceeding. Both parties requested that EPCOR provide additional information on its application, but neither opposed nor argued against the application.

13. In considering whether EPCOR's proposal results in just and reasonable rates, the Commission had to determine the following questions:

(i) Why should an NCP demand charge be included in EPCOR's rate design?

(ii) How will customers be impacted by an NCP demand charge?

(iii) When should this change be implemented?

14. As set out further in this decision, the Commission has concluded that EPCOR's request results in just and reasonable rates and approves EPCOR's application. This is because:

(i) EPCOR's proposed change helps align the price signals set in distribution utilities' tariffs with those approved and set by the Commission in the AESO's tariff. Price signals are important because they signal to customers the cost of their consumption behaviour and encourage efficient resource usage.

(ii) The Commission is satisfied that the bill impacts will not result in rate shock or an undue burden on affected customers.

(iii) EPCOR applied for this change now to reduce potential rate shock for those customers who migrated from FortisAlberta Inc.'s rates to EPCOR's as a result of the City of Edmonton's annexation of outlying land and associated transfer of service territory between the two distribution utilities.

15. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

[4] Exhibit 26836-X0002, application, paragraph 5; Exhibit 26836-X0025, EDTI-CWSAA-2021SEP29-001.

3 Discussion of issues

3.1 Why should an NCP demand charge be included in EPCOR's rate design?

16. EPCOR applied to the Commission to include an NCP demand charge to address inequity resulting from the AESO's and EPCOR's respective tariffs.

17. EPCOR must pay the AESO, on behalf of its customers for accessing the transmission system. Currently, the AESO's tariff recovers the majority of bulk transmission costs through a monthly coincident metered demand charge at each point of delivery. The AESO's coincident metered demand charge is based on a customer's (in this case, EPCOR's) peak demand at each point of delivery, to which it is connected, at the time of the monthly system peak demand. It does not contain any billing minimums.

18. For the rate classes affected by EPCOR's proposal, EPCOR's current SAS rate structure recovers the costs associated with the AESO's coincident peak demand charges through a demand charge that is based on a certain measurement of demand which EPCOR refers to as the customer's billing demand in its rate schedules. The billing demand is calculated as a higher of a customer's actual highest metered demand during the billing period and a number of billing minimums (such as a customer's contracted demand, a specified rate class minimum demand, and a ratchet provision). As a result, customers with varying load patterns, such as seasonal usage, may pay more for bulk transmission costs under EPCOR's current SAS rates than they would if the AESO's coincident metered demand charges were directly applied to end-use customers. In EPCOR's submission, the proposed rate design is more equitable as customers with low NCP demand in a given month will experience lower charges consistent with lower corresponding AESO demand transmission service (DTS) bulk system costs and customers with higher NCP demand in a given month will experience higher charges consistent with higher corresponding AESO DTS bulk system costs.[5]

19. EPCOR also sought to align its rate design with the Commission's direction to Fortis to recover the cost of bulk transmission coincident peak charges through a NCP demand charge for Fortis's commercial and industrial customers.[6]

20. EPCOR proposed to retain a demand charge with billing minimums to collect its billing capacity-related charges arising from the AESO's tariff. EPCOR labelled these charges as "capacity charges" in its updated rate schedule.

21. The Commission finds that EPCOR's proposed changes to its SAS rate design assist in aligning EPCOR's rate design for the transmission costs portion of its distribution tariff with the AESO's current rate design, which allows for the AESO's intended price signal to be passed through more closely to end-use customers.

[5] Exhibit 26836-X0002, application, paragraph 19.

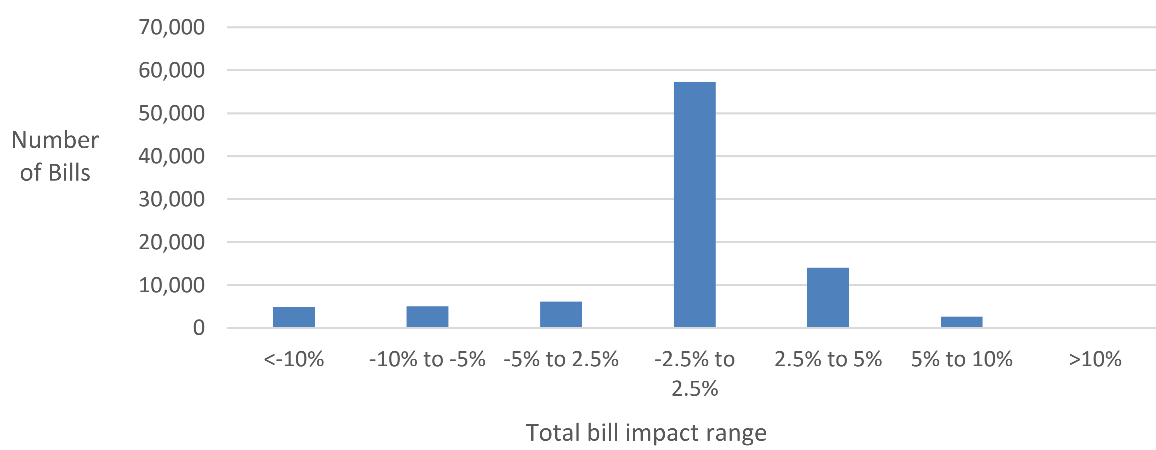
[6] In Decision 2014-018: FortisAlberta Inc., 2012-2014 Phase II Distribution Tariff, Proceeding 2363, Application 1609211-1, January 27, 2014, Section 9.1, the Commission directed Fortis to include an NCP demand charge in its rate design for its Rate 61 and Rate 63 customers. In Decision 25916-D01-2021: FortisAlberta Inc., 2022 Phase II Distribution Tariff Application, Proceeding 25916, July 8, 2021, the Commission approved this same approach for its Rate 41 customers.

3.2 How will customers be impacted by an NCP demand charge?

22. EPCOR explained that for months when a customer's NCP demand equals its billing demand, its SAS charges will increase slightly under the new rate structure. On the other hand, in months where a customer's NCP demand is low compared to its billing demand, its SAS charges will decrease under the new rate structure.[7] Customers whose peak demand varies from month to month will see decreases in their bills during the months of low demand. This is because EPCOR's current SAS rates collect both the AESO's coincident peak demand charges and the AESO's billing capacity-related charges using a demand charge with billing minimums (inclusive of a ratchet provision). In contrast, as explained earlier in Section 3.1, EPCOR's proposed SAS rates would only use billing minimums to collect the AESO's billing capacity-related charges. There would be no billing minimums to collect the AESO's coincident peak charges.

23. The Commission finds that the bill impacts resulting from EPCOR's rate design change are acceptable. The Commission arrived at this finding by relying on EPCOR's bill impact analysis. This analysis showed that in most cases there is no significant effect to customers' monthly bills. This is visually represented in Figure 1 where most monthly bills are impacted between +2.5 and -2.5 per cent.

Figure 1. Monthly bill impacts resulting from EPCOR's proposed rate design[8]



24. However, Figure 1 also shows that some customers will experience monthly bill decreases of more than 10 per cent. This is also highlighted in Table 1 below, where EPCOR reported the most positive and negative bill changes experienced by individual sites for each rate class. These customers' monthly bills have sharp decreases because these customer sites have low demand in those months (potentially because the site is inactive or vacant[9]) and the removal of the billing minimums for a portion of the demand charges lowers their charges in those months. Further, the Commission notes the bill impacts provided by EPCOR are on a month-to-month basis. On an annualized basis, the impacts are thus expected to be less extreme.

7 Exhibit 26836-X0019, EDTI-AUC-2021SEP28-001(b).
8 Figure created by the Commission, using Exhibit 26836-X0019, Table EDTI-AUC-2021SEP28-001-01.
9 Exhibit 26836-X0019, EDTI-AUC-2021SEP28-001(b).

Table 1. Most negative and positive monthly bill impacts

Rate class	Largest negative monthly bill change	Largest positive monthly bill change
Medium Commercial	-38.4%	7.7%
Time of Use - Secondary	-45.8%	5.9%
Time of Use - Primary	-40.3%	3.5%
Customer Specific	-26.6%	6.1%

25. The Commission finds these exceptions are acceptable because EPCOR's proposed rate design creates more equitable rates, since customers with lower demand in a given month will experience lower charges, consistent with causing lower AESO bulk transmission charges to EPCOR (assuming these customers' peak demand is similar to their demand at the time of system peak). Likewise, customers with higher demand in a given month will experience higher charges, consistent with causing higher AESO bulk transmission charges to EPCOR (assuming these customers' peak demand is similar to their demand at the time of system peak).

3.3 When should this change be implemented?

26. During the time of EPCOR's application, and as this decision is released, the Commission is actively reviewing a proposal from the AESO to update its bulk and regional tariff rate design (Proceeding 26911). In that proceeding, the AESO has proposed to shift the recovery of its allocated costs, resulting in a lower weighting to demand-based charges and a relatively higher weighting to volumetric-based charges.[10] Accordingly, the Commission asked EPCOR to clarify why EPCOR is applying for a change to its SAS rate design now, while the AESO's tariff could change as a result of the ongoing proceeding.

27. EPCOR explained that it had been working to file this application based on directions made to Fortis by the Commission (cited above), but paused during the AESO's consultations on its bulk and regional tariff rate design. When EPCOR learned that the AESO's preferred tariff structure continued to include a coincident peak demand charge, EPCOR resumed preparing its application to adjust its own rate design.[11]

28. EPCOR provided calculations showing that if its application was accepted and implemented on April 1, 2022, and the AESO's applied-for rate design was accepted and implemented after this date (with EPCOR's rates subsequently updated to align), typical customers would experience bill changes within the range of ±2.5 per cent, and estimated that the most negative (reduced) monthly bill change would be -24.04 per cent and the most positive (increased) bill change would be 8.18 per cent. EPCOR expected that see-sawing of SAS charges (i.e., charges going down and then subsequently up, or vice versa) could be experienced by some customers, but generally SAS charges that would decrease as a result of the proposed changes in this application would also decrease under the AESO's applied-for rate design.[12]

29. Even though Proceeding 26911 is underway, EPCOR was of the view that it is unknown how long that process will take, given possible contention of the AESO's proposed tariff.[13]

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10 Proceeding 26911, Exhibit 26911-X0001, AESO Bulk and Regional Rate Design Application.
11 Exhibit 26836-X0019, EDTI-AUC-2021SEP28-001(c).
12 Exhibit 26836-X0019, EDTI-AUC-2021SEP28-002(a) and (b).
13 Exhibit 26836-X0019, EDTI-AUC-2021SEP28-002(d).

30. EPCOR also explained that it moved forward with its application to align its SAS rates with the AESO's currently approved tariff at this time to reduce potential rate shock for customers that are being migrated from Fortis's rates to EPCOR's. This change in service is occurring as a result of the City of Edmonton's annexation of land and the subsequent transfer of service territory between the two distribution utilities. As explained in the previous section of this decision, Fortis's rate design already includes an NCP demand charge, while EPCOR's currently does not. Thus, EPCOR expects some customers could be negatively impacted under EPCOR's existing rate design.[14]

31. The AESO's bulk and regional tariff rate design was filed on October 15, 2021, and the Commission has set a schedule that provides for the record closing in the fall of 2022.[15] The outcome of the AESO's application is speculative at this time, as is how the changes proposed in this proceeding will interact with any changes to the AESO tariff that may or may not be approved. The AESO tariff will be determined based on the record of proceeding 26911. After the conclusion of Proceeding 26911, alignment of EPCOR's SAS rate design with the AESO tariff may need to be reassessed. However, the Commission finds that EPCOR's proposed timing to implement the rate design changes strikes a balance between addressing the immediate bill impacts resulting from annexation, improving alignment with the current AESO tariff and being mindful of instability in customer bills that might occur if the AESO's bulk and regional tariff design is adjusted as currently proposed.

32. The Commission approves EPCOR's applied-for changes to its SAS rate design, but has determined a compliance filing is necessary in order for EPCOR to incorporate the most recent available information in its calculated SAS rates. In its annual PBR rate adjustment filing,[16] EPCOR applied for its SAS rates that will be effective on January 1, 2022. On November 18, 2021, EPCOR updated those SAS rates to reflect the DTS rates and balancing pool consumer allocation rider applied for by the AESO.[17] The SAS rates applied for in this proceeding, which EPCOR proposed to be effective April 1, 2022, did not incorporate these updates. Accordingly, more recent information needs to be incorporated into the SAS rates applied for in this proceeding before they are made effective. The Commission directs EPCOR to submit a compliance filing containing updated SAS rates, supporting calculations, and EPCOR's standard bill impact analysis, on or before February 15, 2022. To clarify, the updated SAS rates should only reflect the most recent changes to the AESO tariff (rates and riders) as applied for by the AESO or approved by the Commission, if applicable. Other parameters, assumptions and forecasts used in determining the quantum of the AESO charges (such as the pool price forecast, operating reserve percentage, etc.) should be the same as those approved for use in EPCOR's January 1, 2022, SAS rates in the upcoming decision on Proceeding 26852.

[14] Exhibit 26836-X0019, EDTI-AUC-2021SEP28-002(e).
[15] Proceeding 26911, Exhibit 26911-X0162, AUC letter – Issues list and directions on procedure.
[16] Proceeding 26852, EDTI 2022 Annual PBR Rate Adjustment Filing and 2020 Annual Transmission Access Charge Deferral Account True-Up.
[17] Exhibit 26852-X0053, EDTI-Revised SAS and Balancing Pool Cover Letter.

4 Other rate design matters that were identified during this proceeding

33. While testing the application, the Canada West Ski Areas Association asked EPCOR why the demand ratchets on capacity-related charges that will remain for the four affected rate classes are not the same. Namely, they are either:

- 85 per cent of the highest metered demand in a 12-month period,
- 90 per cent of the highest metered demand in a 12-month period, or
- 90 per cent of the highest metered demand in a 24-month period.

34. The Canada West Ski Areas Association also asked EPCOR to explain the rationale underlying the minimum demand for each rate class. For example:

- 5 kVA for the medium commercial customer rate class, which is defined as having a normal maximum demand of greater than or equal to 50 kVA and less than 150 kVA.
- 50 kW for the time-of-use customer rate classes (primary and secondary), which are defined as having a normal maximum demand of greater than or equal to 150 kVA and less than 5,000 kVA.
- 50 kW for the customer specific customer rate classes (standard and totalized), which are defined as having a normal maximum demand of greater than or equal to 5,000 kVA.

35. EPCOR was unable to respond to the Canada West Ski Areas Association's requests. EPCOR explained that the existing demand ratchet values have been in place since 2007 and it has no historical background information regarding how those demand ratchets were established. Accordingly, the Commission directs EPCOR in its next Phase 2 application to review how its billing minimums are set for its capacity charge for each rate class and propose changes as necessary.

5 Order

36. It is hereby ordered that:

(1) EPCOR Distribution & Transmission Inc.'s 2022 shall file a compliance filing to its 2022 system access service Phase 2 application reflecting the findings, directions and conclusions in this decision, by February 15, 2022.

Dated on November 29, 2021.

Alberta Utilities Commission

(original signed by)

Douglas A. Larder, QC
Vice-Chair

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **Company name of counsel or representative**
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI)
Canada West Ski Areas Association (CWSAA)
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP

Alberta Utilities Commission Commission panel D.A. Larder, QC, Vice-Chair Commission staff D. Fedoretz R. Lucas C. Robertshaw

Appendix 2 – Summary of Commission directions

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

1. The Commission approves EPCOR's applied-for changes to its SAS rate design, but has determined a compliance filing is necessary in order for EPCOR to incorporate the most recent available information in its calculated SAS rates. In its annual PBR rate adjustment filing, EPCOR applied for its SAS rates that will be effective on January 1, 2022. On November 18, 2021, EPCOR updated those SAS rates to reflect the DTS rates and balancing pool consumer allocation rider applied for by the AESO. The SAS rates applied for in this proceeding, which EPCOR proposed to be effective April 1, 2022, did not incorporate these updates. Accordingly, more recent information needs to be incorporated into the SAS rates applied for in this proceeding before they are made effective. The Commission directs EPCOR to submit a compliance filing containing updated SAS rates, supporting calculations, and EPCOR's standard bill impact analysis, on or before February 15, 2022. To clarify, the updated SAS rates should only reflect the most recent changes to the AESO tariff (rates and riders) as applied for by the AESO or approved by the Commission, if applicable. Other parameters, assumptions and forecasts used in determining the quantum of the AESO charges (such as the pool price forecast, operating reserve percentage, etc.) should be the same as those approved for use in EPCOR's January 1, 2022, SAS rates in the upcoming decision on Proceeding 26852. .... paragraph 32

2. EPCOR was unable to respond to the Canada West Ski Areas Association's requests. EPCOR explained that the existing demand ratchet values have been in place since 2007 and it has no historical background information regarding how those demand ratchets were established. Accordingly, the Commission directs EPCOR in its next Phase 2 application to review how its billing minimums are set for its capacity charge for each rate class and propose changes as necessary. .... paragraph 35