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Alberta Electric System Operator 2025 ISO Tariff Update Application

Date: November 8, 2024

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1. Introduction

1 Pursuant to sections 30 and 119 of the *Electric Utilities Act*, S.A. 2003, c. E-5.1 (Act), the Alberta Electricity System Operator (AESO) submits this application (Application) to the Alberta Utilities Commission (Commission) for approval of:

a) the proposed 2025 Independent System Operator (ISO) tariff rates and riders;

b) the proposed 2025 Generating Unit Owner's Contribution (GUOC) rates;

c) the updated amounts included in Appendix B-1, *2025 Rate Calculations* and Appendix B-2, *2025 Rate Calculations* (collectively, "Appendix B"); and

d) the proposed administrative revisions to subsection 12.4(1)(c) of section 12, *Miscellaneous* and to Appendix A, *System Access Service Agreement Proformas* of the ISO tariff to change the AESO's head office and mailing address (collectively, the "Address Revisions").

2 This Application also seeks approval from the Commission, pursuant to subsection 82(6) of the Act, of the proposed ISO tariff Rider F, *Balancing Pool Consumer Allocation Rider* for 2025 (Rider F).

1.1 Overview

3 As detailed further below, this Application seeks approval of changes to the rates to be charged by the AESO in 2025 for system access service.

4 If approved, this Application would only change the levels (that is, the dollar-based and percentage of pool price amounts) included in the rates and local investment amounts[1] of the ISO tariff, based on costs and billing determinants forecast by the AESO for the 2025 calendar year.

5 This Application is consistent with the tariff rates update methodology accepted by the Commission in Decision 2010-606[2] and the GUOC methodology approved by the Commission in Decision 22942-D02-2019.[3]

6 Effective February 1, 2025, the new terms and conditions and corresponding rate sheet for Rate DOS, *Demand Opportunity Service* will be implemented, as approved by the Commission in Decision 28989-D01-2024.[4] To reflect this, an additional rate calculations file, Appendix B-2, is included in this Application.

7 This Application also includes proposed updates to the 2025 Rider F and proposed Address Revisions within the ISO tariff.

8 Lastly, the AESO seeks to update the Commission, by way of this Application, that Rider L, *Utility Deferral Adjustment* (Rider L) is being removed from the ISO tariff effective January 1, 2025 as it is no longer in effect. By way of background, Rider L was approved by the Commission in Decision 26684-D01-2021[5] and was closed as of June 18, 2022 in accordance with Commission Decision 26684-D02-2022[6].

9 The AESO is not seeking approval of its 2025 forecast revenue requirement in this Application. The AESO's forecast costs are approved through other processes provided for in relevant legislation, described below. The AESO's 2025 forecast ancillary services costs, losses costs and administrative costs have not, as of the date

[1] Set out in subsection 4.7(2)(b) of the ISO tariff approved in Decision 25175-D02-2020, *2018 ISO Tariff Compliance Filing Pursuant to Decision 22942-D02-2019* and *2020 ISO Tariff Update Application* (November 30, 2020).

[2] Decision 2010-606, *Alberta Electric System Operator 2010 ISO Tariff* (December 22, 2010), paras. 536-545.

[3] Decision 22942-D02-2019, *AESO 2018 ISO Tariff Application* (September 22, 2019), paragraph 323.

[4] Decision 28989-D01-2024, *AESO Updates to Rate DOS Application* (July 31, 2024).

[5] Decision 26684-D01-2021, *Utility Payment Deferral Program: Rate Rider – Electricity* (August 18, 2021), para 42.

[6] Decision 26684-D02-2022, *Utility Payment Deferral Program: Rate Rider – Electricity* (June 17, 2022), para 30.

of filing this Application, been approved by the AESO Board. The AESO will file a letter to advise the Commission of AESO Board approval once it has been received, which is expected in January 2025.

1.2 Organization of Application

10 This Application is organized into the following sections:

1 **Introduction**

2 **2025 Forecast Revenue Requirement** - Summarizes the AESO's forecast revenue requirement for 2025, including costs that have either been approved by the Commission (for transmission facility owner (TFO) tariffs) or proposed for approval by the AESO Board (for ancillary services, transmission line losses, and the AESO's own administration).

3 **2025 Rates and Riders Update** - Discusses the calculation of rate levels based on the 2025 forecast revenue requirement, 2020 classification and functionalization values approved by the Commission in Decision 22942-D02-2019, and the 2025 forecast billing determinants. Rider F, *Balancing Pool Consumer Allocation*, Rider J, *Wind and Solar Forecasting Service Cost Recovery*, and the removal of Rider L, *Utility Deferral Adjustment* are also discussed in this section.

4 **2025 ISO Maximum Investment Levels Update** - Discusses the calculation of 2025 maximum investment levels using the 2025 escalation factor.

5 **Generating Unit Owner's Contribution Rates** - Discusses the methodology, process, and determination of 2025 generating unit owner's contribution rates.

6 **Address Update** – Discusses the references to the AESO's address within the ISO tariff that have been updated to reflect the AESO's address change.

7 **Conclusion**

11 This Application also includes the following appendices:

A **AESO 2025 Business Plan and Budget Proposal** - Document prepared by AESO management in consultation with stakeholders, containing the AESO's proposed 2025 business initiatives and proposed 2025 budgets and forecasts for ancillary services costs, transmission line losses costs, and administrative costs.

B **2025 Rate Calculations** - Microsoft Excel workbooks which calculate the updated dollar and percentage of pool price amounts for the 2025 rates, based on the same methodology used for the AESO's currently approved rates.

C **2025 Escalation Factor and Investment Levels** - Microsoft Excel workbook which calculates the composite inflation index and escalation factor used to update maximum investment levels.

D **2025 Rates, Riders of the ISO Tariff -** The proposed 2025 rates, and riders that incorporate the 2025 updated amounts included as Appendices B-1 and B-2 to this Application.

E **2025 Rates, Riders of the ISO Tariff (blackline)** - The blackline version of the proposed 2025 rates, and riders that incorporate the 2025 updated amounts included as Appendix B-1 and B-2 to this Application.

1.3 Relief Requested

12 For the reasons outlined in this Application, the AESO submits that the proposed updates to the ISO tariff are just and reasonable. Further, the AESO submits that the proposed ISO tariff rate updates and amounts set out in subsections (i) and (ii) below comply with the updated methodology approved by the Commission for the ISO tariff in Decision 2010-606[7] and Commission Decision 22942-D02-2019.[8] The AESO requests that the Commission approve this Application as applied for, including:

(i) the updated amounts included in the 2025 Rate Calculations files, included as Appendix B-1 and Appendix B-2 to this Application;

(ii) the proposed 2025 ISO tariff Rate DTS, Rate FTS, Rate DOS, Rate XOS, Rate XOM, Rate PSC, Rate STS, Rider J, and GUOC Rates;

(iii) the proposed Rider F; and

(iv) the proposed Address Revisions.

13 The AESO respectfully requests that this Application be approved effective January 1, 2025. The AESO further requests that the Commission issue its approval on or before December 20, 2024 to allow for the proposed tariff updates to be implemented by the AESO effective January 1, 2025 on a prospective basis. If the timing of this Application does not permit the granting of final approval on or before December 20, 2024, the AESO requests that the Commission approve this Application on an interim basis effective January 1, 2025, with ISO tariff rates and amounts, set out in subsections (i) and (ii) above, approved on an interim refundable basis.

14 For additional clarity, the AESO requests that the updated rates and riders proposed in this Application apply on a go-forward basis only, commencing on the effective date approved by the Commission. Consistent with the Commission's statements in Decision 2014-242,[9] the AESO submits that the currently approved deferral account rider and reconciliation mechanisms should continue to be used to address any variances between costs and revenues occurring prior to the approval of the applied-for rates. The AESO is not seeking any retroactive adjustments with respect to the rates proposed for approval in this Application.

2. AESO 2025 Forecast Revenue Requirement

15 The AESO's revenue requirement consists of costs related to wires, ancillary services, transmission line losses, and the AESO's own administration (which includes other industry costs and general and administrative costs). The AESO's forecast costs for 2025 are detailed in Table B1 of Appendix B to this Application.

16 The total revenue requirement forecast for 2025 of $2,570.1 million represents a decrease of $47.6 million (or 1.85%) from the 2024 total revenue requirement forecast of $2,617.7 million included in the 2024 ISO Tariff Rates Update Application.[10] The decrease primarily results from a forecast decrease of $111.6 million (or 9.8%) in 2025 ancillary services costs with an increase of $24.0 million (or 6.1%) in 2025 general and administrative costs.

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[7] Decision 2010-606, *Alberta Electric System Operator 2010 ISO Tariff* (December 22, 2010), paras. 536-545.

[8] Decision 22942-D02-2019, *AESO 2018 ISO Tariff Application* (September 22, 2019), para. 323.

[9] Decision 2014-242*, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update* (August 21, 2014), para 617.

[10] Proceeding 28627, *AESO 2024 ISO Tariff Update Application* (December 15, 2023).

2.1 AESO Board Approval of Costs

17 The AESO is not seeking approval of its 2025 forecast revenue requirement in this Application. The AESO's forecast costs are approved through other processes provided for in relevant legislation, described below. These costs, as provided in column A of Table B-1 of Appendix B, are addressed in the AESO *2025 Business Plan and Budget Proposal,* and will be filed separately as Appendix A to this Application.

18 With respect to the AESO's costs, including their approval processes:

a) Wires costs reflect the amounts paid by the AESO to TFOs in the TFO tariffs approved by the Commission under section 37 of the Act. The wires costs forecast included in the AESO *2025 Business Plan and Budget Proposal* reflects TFO tariffs applied for or approved by the Commission at the time the AESO budget was prepared.

b) Ancillary services costs reflect recovery of the prudent costs incurred by the AESO related to the provision of ancillary services acquired from market participants under subsection 30(4) of the Act.

c) Losses costs reflect recovery of the prudent costs of transmission line losses under subsection 30(4) of the Act.

d) Administrative costs reflect the transmission-related costs and expenses incurred by the AESO and described under subsection 1(1)(g) of the *Transmission Regulation*.

19 The ancillary services costs, losses costs, and administrative costs described above are approved by the AESO Board (consisting of the "ISO members" appointed under section 8 of the Act) in accordance with the *Transmission Regulation*. Section 3 of the *Transmission Regulation* requires that the AESO consult with market participants with respect to proposed costs to be approved by the AESO Board. Subsection 48(1) of the *Transmission Regulation* provides that a reference to "prudent" or "appropriate" in the Act in relation to the costs of ancillary services and losses means the amounts of those costs that have been approved by the AESO Board. In addition, subsection 46(1) of the *Transmission Regulation* provides that the AESO's administrative costs, once approved by the AESO Board, must be considered as "prudent" by the Commission unless an interested person satisfies the Commission otherwise.

20 The budget development process (BDP) includes strategically focused consultations that take place well in advance of the budget development cycle. Specifically, senior executive stakeholders meet one-on-one with a subset of AESO Board and Executive members to share their perspectives on what they believe the AESO should be focusing on in the near term. For the current budget cycle, the first set of consultation sessions occurred June 12, 2024, where stakeholders outlined three strategic areas the AESO should consider when developing the 2025 budget, which will be outlined in Appendix A, *Business Plan and Budget Proposal*. A second session was held November 5, 2024, to affirm that the AESO has determined the appropriate areas of focus, priorities, and pace, based on the June 2024 stakeholder consultation.

21 All stakeholder insights and expertise have been considered by the AESO in determining its corporate focus areas and associated priorities for 2025. As of the date of filing this Application, the AESO's 2025 forecast ancillary services costs, losses costs and administrative costs have not been approved by the AESO Board. The AESO will file a letter to advise the Commission of AESO Board approval once it has been received. The AESO Board approval is expected in January 2025.

22 Additional information on the AESO's business priorities and budget for 2025 is available on the AESO Engage website at www.aesoengage.aeso.ca by following the path Home ▶ Projects ▶ Budget Development Process.

2.2 Wires Costs

23 As shown in column A of Table B-1 of Appendix B, the 2025 forecast costs for wires are $2,025.5 million and represent approximately 78.8% of the AESO's transmission revenue requirement.

24 The AESO has determined the 2025 wires costs for TFOs using the following approach, which was described in section 2.2.1 of the AESO's 2014 ISO tariff application and 2013 ISO tariff update,[11] approved in Decision 2010-606, and updated in Decision 22093-D02-2017[12]:

a) If a transmission facility owner has received final Commission approval for its applicable tariff, the AESO includes the approved costs for that transmission facility owner tariff.

b) If a transmission facility owner has applied for its tariff, the Commission has issued an initial decision on the application, and the transmission facility owner has submitted a refiling in compliance with the decision, the AESO includes the transmission facility owner tariff costs included in the refiling.

c) If a transmission facility owner has applied for its tariff but the Commission has not yet issued an initial decision on the application or an initial decision has been issued but the transmission facility owner has not yet submitted its compliance refiling, the AESO includes the most recent of the following: (i) the transmission facility owner tariff costs last approved by the Commission on a final basis for the transmission facility owner plus 72% of any increase or decrease included in the transmission facility owner's tariff application above or below the prior approved costs, and (ii) the transmission facility owner tariff costs last applied-for by the transmission facility owner in a compliance refiling plus 72% of any increase or decrease included in the transmission facility owner's tariff application above or below the prior approved costs.

d) If a transmission facility owner has not yet applied for its tariff, the AESO includes the most recent of the following: (i) the transmission facility owner tariff costs last approved by the Commission on either a final or interim basis, and (ii) the transmission facility owner tariff costs last applied-for by the transmission facility owner in a compliance refiling.

25 As noted in the 2014 ISO tariff application, "the inclusion of 72% of an applied-for increase or decrease in (c) above was determined from the percentages of applied-for changes which had received final approval in recent transmission facility owner tariff applications, and is not meant to indicate any predetermination of the result of a transmission facility owner tariff proceeding, nor be interpreted as AESO support for any specific components of a transmission facility owner tariff application."[13]

26 The TFO tariff costs are included as Table B-2 of Appendix B to this Application.

2.3 Ancillary Services Costs

27 As shown in column A of Table B-1 of Appendix B, the forecast 2025 costs for ancillary services are $252.3 million and represent approximately 9.8% of the AESO's transmission revenue requirement. Ancillary services, as defined in subsection 1(1)(b) of the Act, are services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency. The largest component of ancillary services costs is operating reserve, which represents the real power capability above system demand required to provide for regulation, forced outages and unplanned outages.

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[11] Exhibit 0026.00.AESO-2718, paras. 53-57.

[12] Decision 22093-D02-2017, *Alberta Electric System Operator 2017 ISO Tariff Update* (April 4, 2017), para. 37.

[13] Exhibit 0026.00.AESO-2718, para. 58.

28 Ancillary services costs are primarily a function of volume forecasts and market-based commodity pricing forecasts. The 2025 forecast costs for ancillary services were based on a forecast average pool price of $54.30/MWh.

2.4 Losses Costs

29 As shown in column A of Table B-1 of Appendix B, the 2025 forecast costs for transmission line losses are $136.9 million and represent approximately 5.3% of the AESO's transmission revenue requirement. Losses are the energy lost on the transmission system when power is transmitted from suppliers to loads. Losses are the residual of the metered generation plus scheduled imports less metered loads and less scheduled exports.

30 Losses costs are a function of volume forecasts and market-based commodity pricing forecasts. The 2025 forecast costs for losses were based on a forecast average pool price of $54.30/MWh.

2.5 Administrative Costs

31 As shown in column A of Table B-1 of Appendix B, the 2025 general and administrative and other industry costs are $155.5 million and represent approximately 6.1% of the AESO's transmission revenue requirement.

32 Administrative costs are defined in paragraph 1(1)(g) of the *Transmission Regulation* as follows:

> 1(1)(g) "ISO's own administrative costs" means
>
> (i) the transmission-related costs and expenses of the ISO respecting the administration, operation and management of the ISO,
>
> (ii) the transmission-related costs and expenses of the ISO respecting reliability standards and reliability management systems, and
>
> (iii) the transmission-related costs and expenses required to be paid, or otherwise appropriately paid, by the ISO, except for the following:
> (A) costs for the provision of ancillary services;
> (B) costs of transmission line losses;
> (C) amounts payable under TFO transmission tariffs.

33 The AESO Board approves the AESO's administrative costs in their entirety. However, only the transmission-related portions of those costs (as defined in subsection 1(1)(g) of the *Transmission Regulation*) are recovered through the ISO tariff. Further, the AESO *2025 Business Plan and Budget Proposal* allocates administrative costs among the four functions of the AESO; namely, transmission, energy market, renewables (the Renewable Electricity Program) administration and load settlement.

3. 2025 Rates and Riders Update

34 The 2025 rate calculations are included as Appendix B to this Application, in Tables B-1 through B-16.

35 The rate calculations use the following inputs:

(a) the 2025 forecast revenue requirement discussed in section 2 of this Application;

(b) the functionalization and classification of wires costs and the point of delivery cost function approved for 2020 in Decision 22942-D02-2019;[14] and

(c) the 2025 forecast billing determinants prepared by the AESO.

3.1 Specific Rate Changes

36 Where applicable, rates in the ISO tariff have been updated to reflect the 2025 forecast revenue requirement, the 2020 classification and functionalization of wires costs, and the 2025 forecast billing determinants. Specifically, levels of dollar-based and percentage of pool price amounts have been updated in the following rates:

- Rate DTS, *Demand Transmission Service*;
- Rate FTS, *Fort Nelson Demand Transmission Service*;
- Rate PSC, *Primary Service Credit;*
- Rate DOS, *Demand Opportunity Service*;
- Rate XOS, *Export Opportunity Service*; and
- Rate XOM, *Export Opportunity Merchant Service*.

37 The levels for each of the above rates have been calculated in accordance with Appendix B to this Application. As described in section 1 above, two appendices have been filed as Appendix B, *2025 Rate Calculations* and are included with this Application. These appendices reflect the rates calculated based on the current Rate DOS, in effect up to and including January 31, 2025, and the updates to Rate DOS approved in Decision 28989-D01-2024[15], which will take effect on February 1, 2025.

38 The approved updates to Rate DOS, to take effect on February 1, 2025, will result in an increase to Rate DTS revenue offsets of approximately $0.8 million, which causes a slight decrease to Rate DTS, Rate FTS, Rate PSC, Rate XOS, and Rate XOM from the amounts set out in Appendix B-1. A comparison of the impact to the connection charge has been summarized in Table 3.1.

39 With the exception of the Rate DOS rate sheet that the AESO is proposing be in effect from January 1, 2025 to January 31, 2025, inclusive (Appendix D-1), the updated ISO tariff rate sheets for 2025, included as Appendix D to this Application, are based on the rates calculated in Appendix B-2. Considering the slight variation between the rates in Appendix B-1 and B-2, the one month time difference, and to minimize administrative burden, the AESO is requesting that the Rate DTS, Rate FTS, Rate PSC, Rate XOS, Rate XOM values shown in Appendix B-2 and Appendix D be approved to take effect on January 1, 2025. Appendix B-1 has been included as it reflects the rate calculation proposed for Rate DOS for January 2025 and for reference purposes for comparison with the rates calculated in Appendix B-2.

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[14] Exhibit 22942-X0025, Appendix D, Transmission System Cost Causation Study 2018 Update dated September 14, 2017, page 5, Table D-5. At the time of writing this application, the 2020 classification and functionalization values were the most recently approved values available. See also: Decision 26911-D01-2022, *Alberta Electric System Operator Bulk, Regional and Modernized Demand Opportunity Service Rate Design Application,* para 156, which orders the AESO's current rate design continue until further order or decision of the Commission.

[15] Decision 28989-D01-2024, *Updates to Rate Demand Opportunity Service* (July 31, 2024).

Table 3-1 – 2025 Proposed Rates Comparison

	2025 Rates Appendix B-1	2025 Rates Appendix B-2	Decrease	Decrease
Connection Charge			**Amount $ 000 000**	**Percent %**
Bulk System Charge — Demand	$ 11,168.00	$ 11,164.00	-$4.00	0.04%
Bulk System Charge — Usage	$ 1.23	$ 1.23	$0.00	0.00%
Regional System Charge — Demand	$ 2,946.00	$ 2,945.00	-$1.00	0.03%
Regional System Charge — Usage	$ 0.93	$ 0.93	$0.00	0.00%
POD Charge — Customer × SF	$ 15,310.00	$ 15,304.00	-$6.00	0.04%
POD — Demand ≤ (7.5×SF) MW	$ 5,039.00	$ 5,037.00	-$2.00	0.04%
POD — Demand > (7.5×SF) to ≤ (17×SF) MW	$ 2,988.00	$ 2,987.00	-$1.00	0.03%
POD — Demand > (17×SF) to ≤ (40×SF) MW	$ 2,000.00	$ 2,000.00	$0.00	0.00%
POD — Demand > (40×SF) MW	$ 1,232.00	$ 1,231.00	-$1.00	0.08%

40 In summary, the AESO requests the approval of the rates included in Appendix B as follows:

(i) Appendix B-1 - applicable to the proposed Rate DOS, *Demand Opportunity Service* (Rate DOS) effective January 1, 2025 to January 31, 2025, inclusive; and

(ii) Appendix B-2 - applicable to the proposed:

- Rate DOS effective February 1, 2025 through December 31, 2025, inclusive; and
- Rate DTS, Rate FTS, Rate PSC, Rate XOS, and Rate XOM, effective January 1, 2025 through December 31, 2025, inclusive.

3.1.1 Rate DOS, Demand Opportunity Service

41 Existing Rate DOS will remain in effect from January 1, 2025 through January 31, 2025, inclusive, and the rates calculated for this period are reflected in Appendix B-1 and are included in the Rate DOS rate sheet, filed as Appendix D-1.

42 Changes to implement the amended Rate DOS are reflected in the rate calculations in Appendix B-2 and included in the Rate DOS rate sheet filed as Appendix D-2, to come into effect on February 1, 2025.

3.1.2 Rate PSC, Primary Service Credit

43 The 2025 primary service credit is calculated as[16]:

- 79% of the substation fraction ($/month) tier of the Rate DTS point of delivery charge;
- 79% of the first three capacity (7.5 MW, 9.5 MW, and 23 MW) tiers of the Rate DTS point of delivery charge; and
- 100% of the fourth capacity (remaining capacity above 40 MW) tier of the Rate DTS point of delivery charge.

[16] Decision 2010-606, *Alberta Electric System Operator 2010 ISO Tariff* (December 22, 2010), Table 2.

44 As the Rate DTS point of delivery charge has been updated in this Application, the AESO has correspondingly updated the primary service credit as provided in Table B-8 of Appendix B to this Application.

3.2 Rider J, Wind and Solar Forecasting Service Cost Recovery Rider

45 As the AESO explained in its 2014 ISO tariff application, charges under Rider J recover both costs associated with the AESO's contracted wind forecasting service as well as variances from forecasts of costs and energy initially used to determine the values of the rider.[17] In Commission Decision 26980-D01-2021, the Commission approved amendments to Rider J to include the additional recovery of forecasting service costs for solar-powered generating units. In 2025, Rider J is expected to recover all costs of the contracted wind and solar forecasting service that have been incurred since it was initially implemented in 2011.

46 On a cumulative forecast basis, the AESO is forecast to over collect $34,099 through Rider J by the end of 2024. The wind and solar annual forecasting service cost for 2025 is forecast to be $196,500, representing an increase of $107,475 from the expected annual forecasting service cost of $89,025 in 2024. The increase in costs for 2025 results from the addition of a second forecasting provider due to the overall increase in wind and solar facilities in the province. Given that the cumulative balance by the end of 2024 is expected to be a surplus collection of $34,099, and next year's costs are forecast to be $196,500, the AESO proposes to set the Rider J charge at $0.01/MWh.

47 The proposed 2025 Rider J charge will remain at $0.01/MWh, as it is in the current ISO tariff, for the recovery of the forecasting service costs. Table 3-2 below illustrates the changes from year to year to achieve as close to a zero balance as possible at the end of 2025. Table 3-2 only includes forecast solar costs, volumes and revenues starting in 2022.

Table 3-2 – Wind and Solar Forecasting Service Cumulative Balance

Line No.	Description	Actual 2010 – 2021	Actual 2022	Actual 2023	Forecast 2024	2025
1	Contracted wind and solar forecasting service* ($000)	$3,252.1	$54.6	$74.4	$89.0	$196.5
2	Volumes (GWh)	44,369.5	7,826.6	11,867.5	17,303.3	20,000.4
3	Rider J Charge ($/MWh)	-	0.01	0.00	0.01	0.01
4	Revenue ($000)	3,294.8	66.1	0.00	143.3	200.0
5	Annual (undercollection) / overcollection ($000)	42.7	11.5	(74.4)	54.3	3.5
6	**Cumulative Balance (undercollection) / overcollection ($000)**	**$42.7**	**$54.2**	**($20.2)**	**$34.1**	**$37.6**

* Assumes solar forecasting begins in 2022

[17] Exhibit 0026.00.AESO-2718, paras. 124-126.

3.3 Rider F, Balancing Pool Consumer Allocation

48 The AESO is seeking approval of the 2025 ISO tariff Rider F, providing for a $1.30 per megawatt hour (MWh) charge for all demand transmission service (Rate DTS) and demand opportunity service (Rate DOS) market participants (excepting the City of Medicine Hat and BC Hydro at Fort Nelson) for metered energy from January 1, 2025 through December 31, 2025, inclusive.

49 The Balancing Pool is a corporation established under subsection 75 of the Act. Pursuant to subsection 82(1) of the Act, the Balancing Pool is required to prepare a budget for each fiscal year setting out its estimated revenues and expenses to carry out its powers, duties, responsibilities, and functions under the Act. Based on this forecasted budget, the Balancing Pool notifies the AESO under subsection 82(4) of the Act of an annualized amount to be credited (or charged) to market participants for each fiscal year. Under subsections 82(5), 30(1) and 30(2)(b) of the Act, the AESO must include this annualized amount in the ISO tariff, and has done so through Rider F.

50 Rider F is applicable to all Rate DTS and Rate DOS market participants excepting the City of Medicine Hat and BC Hydro at Fort Nelson in accordance with Order U2006-307, wherein the predecessor to the Commission held the City of Medicine Hat and BC Hydro at Fort Nelson were ineligible for Rider F.

51 On September 27, 2024 the Balancing Pool notified the AESO of a consumer charge for 2025 of $1.30/MWh for an estimated annualized amount of $78,159,810.30. A copy of the Balancing Pool's notice to the AESO is included as Appendix F to this Application.

52 The AESO has confirmed that the proposed $1.30/MWh consumer charge for Rider F for metered energy from January 1, 2025 to December 31, 2025 is expected in order to charge the annualized amount to all market participants receiving service under Rate DTS and Rate DOS (excepting the City of Medicine Hat and BC Hydro at Fort Nelson) on a forecast basis.

Table 3-3 – Rider F Calculation

[A]	[B]	[C]	[D = B ÷ C]
Period	**Annualized Amount Refund (Charge)**	**Metered Energy Forecast MWh**	**Annual Credit (Charge) $/MWh**
January - December 2025	($78,159,810.30)	60,122,931	($1.30)

53 The AESO proposes that all substantive aspects of Rider F, including applicability criteria and use of a $/MWh amount approach, continue unchanged for 2025 metered energy from the Rider F that is currently in effect.

54 The proposed Rider F is included as Appendix E to this Application. The format and language of the proposed Rider F is the same as the currently approved Rider F.

3.4 Rider L, Utility Deferral Adjustment

55 Rider L is being removed from the ISO tariff, effective January 1, 2025, as it is no longer in effect. By way of background, Rider L was approved by the Commission in Decision 26684-D01-2021[18] to recover transmission and energy charges deferred by electricity customers in accordance with section 5 of the *Utility Payment Deferral Program Act*, as well as associated carrying costs, and to recover the funding amounts that the

[18] Decision 26684-D01-2021, *Utility Payment Deferral Program: Rate Rider – Electricity* (August 18, 2021).

Balancing Pool provided to electricity service providers as well as the associated administration expenses incurred by the Balancing Pool. Rider L was closed as of June 18, 2022 in accordance with Commission Decision 26684-D02-2022[19] and can be removed from the ISO tariff.

3.5 2025 Forecast Billing Determinants

56 The rate calculations for the 2025 rates update are based on the AESO's forecast of billing determinants for 2025. The 2025 billing determinants are estimated using a combination of historical analysis and a DTS energy forecast that is described below. The updated DTS energy forecast, developed using a methodology similar to that applied to create the AESO's 2024 Long-Term Outlook (LTO) with the most up to date actual load data and economic outlook, was used to estimate the billing determinants. The DTS energy forecast is generated from historic trends and economic growth (gross domestic product, population and employment) information and oilsands production forecasts. The AESO 2024 LTO, including its data file, is available on the AESO website at www.aeso.ca by following the path Grid ▶ Grid Planning ▶ Forecasting. A comparison of the billing determinants used in the 2025 and 2024 rate calculations are provided in Table B-12 of Appendix B to this Application.

57 Table 3-4 below provides a comparison of the forecast billing determinants in this Application as well as the forecast used in 2024 ISO tariff update application to the 2022 and 2023 recorded billing determinants. Based on the economic modelling described above, the AESO expects load growth in 2025. This is shown in Table 3-2 below, where the 2025 billing determinant forecast shows an increase over the 2024 forecast for all determinants, which is also in line with year-to-date recorded values for 2024.

Table 3-4 – 2025 and 2024 Forecast and 2023 and 2022 Recorded Billing Determinants

Rate DTS Billing Determinants	Units	2025 Forecast	2024 Forecast	2023 Recorded[20]	2022 Recorded
Coincident Metered Demand	MW-months	**94,548.4**	92,997.9	92,382.9	94,390.6
Billing Capacity (Total)	MW-months	**163,368.8**	162,554.2	162,127.9	162,453.3
Highest Metered Demand	MW-months	**124,302.6**	123,610.9	120,804.4	121,893.5
Metered Energy (All Hours)	GWh	**60,430.8**	58,383.5	60,112.9	59,772.2
Market Participants (Total)	customer-months	**5,404.3**	5,399.2	5,364.8	5,360.2

58 The AESO considers that the 2025 forecast provides the best estimate of billing determinants for the rate calculations in this Application given the available information.

3.6 Bill Impacts

59 As noted in sections 2 and 3.5 of this Application, the AESO's 2025 forecast revenue requirement has decreased primarily due to a decrease in operating reserves costs and the AESO's 2025 forecast of billing determinants has increased. The connection charge under the AESO's 2025 updated Rate DTS will increase by 3.1% mainly due to an increase in wires costs. When all DTS charges are considered, the AESO's 2025

[19] Decision 26684-D02-2022, *Utility Payment Deferral Program: Rate Rider – Electricity* (June 17, 2022), para 30.

[20] As per exhibit 29139-X0002 in AUC Proceeding 29193 AESO 2023 *Deferral Account Reconciliation Application,* table 3-1.

updated rates represent an overall increase of 2.9% from the 2024 rates, with connection charges making up the majority of the increase to Rate DTS.

60 While the AESO includes an estimate of the operating reserve charge, operating reserve costs are settled monthly based on the actual costs incurred and therefore the estimate of operating reserve costs do not impact the calculation for the proposed Rate DTS within this Application. The estimate of Rate STS is expressed as a percentage of the cost of losses and overall revenue from STS, and is forecast to increase by 17.7% in 2025 relative to 2024 due to the forecasted pool price decreasing in the denominator. The overall result is an increase of 3.5% to the 2024 rates currently in place when considering changes to both DTS and STS.

61 Deferral accounts provide certainty that the AESO's costs will be exactly recovered by revenue, either through base rates or through the deferral account rider and reconciliations. Adjustments to costs paid by the AESO will therefore flow to and impact market participants through deferral accounts if rates are not adjusted. The changes in rates summarized above improve the timeliness and accompanying accuracy of the recovery of costs from market participants.

62 The increases to the different components of Rate DTS are provided in Table B-13 of Appendix B-2 to this Application. The Rate DTS increase of 2.9% represents a revenue-weighted average increase over all components of Rate DTS.

63 Individual bill impacts experienced by market participants will vary, depending on the specific characteristics of a market participant's service including peak demand coincidence, billing capacity, load factor, and hourly pool price and transmission constraint rebalancing charge at the time of usage.

64 To allow individual market participants to estimate the impact of the 2025 rates on their own Rate DTS bills, the AESO has included a bill impact estimator as Table B-16 in the rate calculations included as Appendix B-2 to this Application. The bill impact estimator calculates bills for a given set of billing inputs under both the current 2024 Rate DTS and the updated 2025 Rate DTS, to allow the impact of the rates update on an individual service to be estimated.

65 The changes to the different components of Rate STS are provided in Table B-13 of Appendix B-2 to this Application. The Rate STS increase of 17.7% represents a revenue-weighted average increase over all components of the rate.

66 Individual bill impacts experienced by market participants will vary, depending on the specific characteristics of a market participant's system access service.

67 In particular, the AESO notes that the loss factors provided in Table B-13 of Appendix B-2 to this Application are representative average loss factors only. The actual losses charge applicable to an individual market participant will be based on a location-specific loss factor determined in accordance with section 501.10 of the ISO rules, *Transmission Loss Factors* (Section 501.10), as specified in the ISO tariff Rate STS, *Supply Transmission Service*. Section 501.10 was approved by the Commission in Decision 790-D05-2016[21] in Proceeding 790, although the AESO notes that the losses charge remains as approved on an interim basis in Commission Decision 2014-242.[22]

[21] Decision 790-D05-2016, *Milner Power Inc. and ATCO Power Ltd. Complaints Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology* (November 30, 2016), para. 1.

[22] Decision 2014-242, *AESO 2014 ISO Tariff Application and 2013 ISO Tariff Update* (August 21, 2014), para. 730.

4. Maximum Investment Levels Update

68 This Application includes updated investment amounts approved in Decision 22942-D02-2019[23] to revise the existing point of delivery cost curve to Option 2[24] and reflect an escalation factor based on a composite of specified recent inflation indices.

69 The AESO has accordingly updated the composite inflation index used for developing the point of delivery cost function to 2025, using additional Statistics Canada cost index values and the most recent Conference Board of Canada forecast of the Alberta consumer price index. Appendix C included in this Application provides the composite inflation index values for 2018 to 2025 on the Escalation Factor sheet, and the 2025 investment levels on the 2025 Investment sheet.

70 The resulting escalation factor for updating the 2025 maximum investment levels in section 4 of the ISO tariff, *Classification and Allocation of Connection Projects Costs* (Section 4), is 1.1949, which represents an increase to the 2018 maximum investment levels. The increase reflects increases in the latest underlying indices used for the composite index. The detailed calculation of the composite inflation index is included in Appendix C of this Application.

71 The AESO has applied the resulting 1.1949 escalation factor to the 2018 Rate DTS maximum investment levels to determine the 2025 Rate DTS maximum investment levels, as summarized in the 2025 Investment sheet included in Appendix C to this Application. The 2024 escalation factor of 1.1707 used in the 2024 ISO Tariff Update Application[25] was lower than the 2025 escalation factor of 1.1949, resulting in an increase to the 2025 investment levels.

5. Generating Unit Owner's Contribution Rates

72 The proposed 2025 GUOC rates reflect a change from the approved 2024 GUOC rates for the Central planning region. There are no other changes proposed to the GUOC rates for 2025 relative to the 2024 GUOC rates. The AESO determined the proposed 2025 GUOC rates following the process approved by the Commission in Decision 27777-D01-2022[26]. The AESO also posted the proposed 2025 GUOC rates on the AESO website on July 29, 2024 to give market participants advance notice of the proposed rates.

73 The GUOC rates are determined using qualitative assessment based on engineering studies, in accordance with the methodology approved in Decision 22942-D02-2019.[27] The balance of load and generation for all planning regions are expected to remain largely the same in 2024, with no material changes. The proposed 2025 GUOC rates, differentiated by region, have been developed following the criteria and engineering study results described below.

74 In each region, the GUOC charge consists of the sum of two components:

1. $10,000/MW, payable by all Generation Facility Owners (GFOs) regardless of location in the province
2. A charge (of not more than $40,000/MW) payable by all GFOs, which varies by region based on the following criteria:

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[23] Decision 22942-D02-2019, *AESO 2018 ISO Tariff Application* (September 22, 2019) para 201.

[24] Exhibit 22942-0018.03, Appendix G – Options for POD Cost Function Workbook, Tab 'Option 2 Investment Proposed', Cells C11 to G11.

[25] Exhibit 28627-0005, Appendix C - 2024 Escalation Factor and Investment Levels, Tab 'Escalation Factor', Cell E15.

[26] Decision 27777-D01-2023, *2023 Independent System Operator Tariff Update* (December 21, 2022), paras. 27 -28.

[27] Decision 22942-D02-2019, *AESO 2018 ISO Tariff* (September 22, 2019), paragraph 323.

- $0/MW: generation development in the region can help defer load driven transmission development:
    a) Northwest planning region: All prior AESO LTPs and more recent engineering studies have indicated that new generation in the Northwest planning region is desirable.

- $10,000/MW: the region has significant existing or near-term generation integration capability[28]:
    a) Edmonton planning region: With coal generation facilities retired or re-powered to gas operation, the AESO anticipates the Edmonton planning region has significant generation integration capability. This is also demonstrated in the 2022 Long Term Plan (LTP).

- $20,000/MW: the region has limited existing or near-term generation integration capability and limited development interest:
    a) Northeast planning region: The anticipated co-generation development at Suncor Energy Inc. will reduce the available generation integration capability.

    b) Calgary planning region: Being one of the load centres in Alberta, Calgary planning region can benefit from generation developments in strategic locations. However, some of the key 240 kV lines transferring power into the region, such as the line going north from Shepard, are heavily loaded with limited available generation integration capability.

- $30,000/MW: the region has limited existing or near-term generation integration capability and significant development interest
    a) Central planning region: The change to the Central planning region GUOC rates reflects the current substantial interest in the Central East region. While the Central East Transfer Out (CETO) project can help alleviate congestion, strong interest for generation projects in the Central region is expected to continue following the initiation of the second stage of the CETO project earlier in 2024.

- $40,000/MW: the region does not have existing or near-term generation integration capability.
    a) South planning region: Congestion on the transmission system has occurred in the South planning region. In addition, congestion is anticipated in more planning areas within the South planning region driven by strong interests in renewables developments. As a result, there is limited or no generation integration capability in some planning areas and the AESO is developing transmission plans to mitigate congestion in the region.

75 The proposed 2025 GUOC rates, which the AESO is requesting to be made effective January 1, 2025, are set out in subsection 7.3(1) of the ISO tariff, as follows:

[28] Generation integration capability is strongly related to the total generation and load in the region. Typically, generation integration capability is higher in regions where load is higher. Therefore, there is an implicit relationship between generation integration capability and proximity to load. As a result, setting GUOC rates based on existing and near-term generation integration will incent generation to locate in areas of the transmission system where load exceeds generation.

Table 5-1 – 2025 Generating Unit Owner's Contribution Rates

Planning Region	2025 Rate ($/MW)	Current Rate ($/MW)
Northwest	$10,000	$10,000
Northeast	$30,000	$30,000
Edmonton	$20,000	$20,000
Central	$40,000	$20,000
Calgary	$30,000	$30,000
South	$50,000	$50,000

6. Address Change

76 The AESO is seeking approval of changes to subsection 12.4(1)(c) of section 12, *Miscellaneous* and to Appendix A, *System Access Service Agreement Proformas* of the ISO tariff, effective January 1, 2025, to update its head office and mailing address. The proposed changes are set out in Appendix G.

7. Conclusion

77 For the foregoing reasons, AESO requests that the Commission grant the approval of this Application, as applied for, and the relief requested in section 1.3 of this Application.

All of which is respectfully submitted this 8th day of November, 2024.

Alberta Electric System Operator

Per: "*Annie Nguyen*"

Annie Nguyen

Manager, Tariff