Alberta Electric System Operator 2021 ISO Tariff Update

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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 AESO applies to the Alberta Utilities Commission ("Commission") for approval of its 2021 update to the Independent System Operator ("ISO") tariff ("Update Application"). As detailed further below, this Update Application seeks approval of changes to the rates to be charged by the AESO in 2021 for system access service and to the maximum investment levels provided for in the ISO tariff.

2 If approved, this Update Application would change only 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 2021 calendar year. The Update Application also includes changes resulting from the Commission's acceptance of the 2018 Transmission Cost Causation Study update in Decision 22942-D02-2019.[2]

3 This Update Application also proposes revisions to remove the regulated generating unit connection cost provisions of the ISO tariff, as discussed in section 3.1.2 below.

4 This Update Application is consistent with the tariff update methodology accepted by the Commission in Decision 2010-606.[3]

5 The AESO notes that the form of ISO tariff filed as Appendices D and E of this Update Application assumes that the tariff applied-for by the AESO in Proceeding 25175,[4] regarding the AESO's 2018 ISO tariff compliance filing, will be approved by the Commission with effect as of January 1, 2021.[5] If the tariff applied-for in Proceeding 25175 will not be made effective by January 1, 2021, an amendment to this Update Application may be required.

1.1 Organization of Application

6 This Update Application is organized into the following sections:

1 **Introduction** — Provides background on the Update Application and specifies the relief requested.

2 **2021 Forecast Revenue Requirement** — Summarizes the AESO's forecast revenue requirement for 2021, 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 **2021 Tariff Update** — Discusses the calculation of rate levels based on the 2021 forecast revenue requirement, 2021 wires costs functionalization and classification approved by the Commission in Decision 22942-D02-2019 and 2021 forecast billing determinants.

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[1] Set out in subsection 8(2)(b) of section 8 of the current ISO tariff, and subsection 4.7(2)(b) of the ISO tariff applied for in Proceeding 25175 (Exhibit 25175-X0116).
[2] Decision 22942-D02-2019, *Alberta Electric System Operator*, *2018 Independent System Operator Tariff* (September 22, 2019), para. 74.
[3] Decision 2010-606, *Alberta Electric System Operator 2010 ISO Tariff* (December 22, 2010), paras. 536-545.
[4] Exhibit 25175-X0116.
[5] In accordance with the AESO's request in Exhibit 25175-X0119.

4 **2021 ISO Maximum Investment Levels Update** – Discusses the calculation of 2021 maximum investment levels using the 2021 escalation factor.

5 **Conclusion —** Reiterates the relief requested**.**

7 This Update Application also includes the following appendices:

A **AESO 2021 Business Plan and Budget Proposal** — Document prepared by AESO management in consultation with stakeholders, as proposed on October 29, 2020, containing the AESO's proposed 2021 business initiatives and proposed 2021 budgets and forecasts for ancillary services costs, transmission line losses costs, and administrative costs.

B **2021 Rate Calculations** — Microsoft Excel workbook which calculates the updated dollar and percentage of pool price amounts for the 2021 rates, based on the same methodology used for the AESO's currently approved rates.

C **2021 Escalation Factor and Investment Levels** — Microsoft Excel workbook which calculates the composite inflation index and escalation factor used to update maximum investment levels.

D **2021 Rates, Riders, and Section 8 of the ISO Tariff** — The proposed 2021 rates, riders, and section 8[6] that incorporate the 2021 updated amounts included as Appendices B and C to this Update Application.

E **2021 Rates, Riders, and Section 8 of the ISO Tariff (blackline)** — The blackline version of the proposed 2021 rates, riders, and section 8[7] that incorporate the 2021 updated amounts included as Appendices B and C to this Update Application.

1.2 Relief Requested

8 For the reasons outlined below, the AESO submits that the tariff updates proposed in this Update Application are just and reasonable, and respectfully requests that the Commission approve this Update Application, including (i) the updated amounts included as Appendix B to this Update Application, (ii) the proposed 2021 ISO tariff Rate DTS, Rate FTS, Rate DOS, Rate XOS, Rate XOM, Rate PSC, Rate STS, Rider J and Section 8[8] included as Appendix D to this Update Application, which incorporates the updated amounts; and (iii) the revisions to the terms and conditions of the ISO tariff set out in Appendix D to this Update Application, required to remove reference to regulated generating unit connection costs.

9 The AESO respectfully requests that this Update Application be approved effective January 1, 2021. The AESO further requests that the Commission issue its approval on or before December 28, 2020 as this is the last approval date that will allow the AESO to implement the proposed tariff updates effective January 1, 2021 on a prospective basis and inform market participants in advance of rate changes. If the timing of this Update Application does not permit the granting of final approval on or before December 28, 2020, the AESO also requests that the Commission issue its approval on an interim refundable basis.

10 For additional clarity, the AESO requests that the updated rates, riders and investment levels proposed in this application apply on a go-forward basis only, commencing from the effective date approved by the

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[6] Set out in Section 8 of the current ISO tariff, and Section 4 of the ISO tariff applied for in Proceeding 25175 (Exhibit 25175-X0116).
[7] *Ibid.*
[8] Section 8 of the current ISO tariff, and Section 4 of the ISO tariff applied for in Proceeding 25175 (Exhibit 25175-X0116).

Commission. Consistent with the Commission's statements in Decision 2014-242,[9] the AESO submits that 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 Update Application.

2 AESO 2021 Forecast Revenue Requirement

11 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 2021 are detailed in column A of Table 2-1. For comparison, Table 2-1 includes forecast costs for 2020, and the recorded costs for 2019 and 2018, in columns B, C, D, and E, respectively.

Table 2-1 – 2021 and 2020 Forecast, 2019 and 2018 Recorded Cost Components

Cost Component	2021 Forecast ($ 000 000) A	2020 Forecast ($ 000 000) B	2019 Recorded ($ 000 000) D	2018 Recorded ($ 000 000) E
Wires	1,951.6	1,916.0	1,849.7	1,782.5
Ancillary services	198.3	258.4	213.0	277.8
Losses	104.4	113.5	106.5	98.3
Administrative	114.5	99.1	112.4	104.5
Revenue Requirement	**2,368.8**	**2,387.0**	**2,281.6**	**2,263.1**

Note: Numbers may not add due to rounding

12 The 2021 forecast costs represent a decrease of $18.3 million (or 0.8%) over the 2020 forecast costs included in the 2020 ISO tariff update application. The decrease results from a forecast decrease of $60.1 million (or 23.3%) in ancillary services costs, which is partly offset by an increase of $35.6 million (or 1.9%) in wires costs.

2.1 AESO Board Approval of Costs

13 The AESO is not seeking approval of its 2021 forecast revenue requirement in this Update Application. The AESO's forecast costs are approved through other processes provided for in relevant legislation. These costs, as provided in column A of Table 2-1, were addressed in the AESO *2021 Business Plan and Budget Proposal,* dated October 29, 2020 and included as Appendix A to this Update Application.

14 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 *2021 Business Plan and Budget Proposal* reflected TFO tariffs applied for or approved by the Commission at the time the AESO budget was prepared.

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

(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*.

15 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* addresses consultation and approval of those costs and 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.

16 The practice established by the AESO to carry out consultation on ancillary services, losses, and administrative costs is the Budget Review Process. The Budget Review Process is a transparent stakeholder process which provides a prudence review with input from stakeholders. At the conclusion of the Budget Review Process, AESO management proposes a business plan and budget to the AESO Board, including a request for approval of ancillary services costs, losses costs, and administrative costs.

17 As part of the AESO Budget Review Process for its 2021 budget, AESO management consulted with stakeholders in a planning process that had been first established with stakeholders in 2005. The *2021 Business Plan and Budget Proposal* includes details on the consultation process and on the proposal for the AESO's business plan and budget as it relates to forecasted ancillary services costs, forecasted losses costs, and the AESO's business priorities and budget for 2021. The *2021 Business Plan and Budget Proposal* was also provided to stakeholders and posted on the AESO website.

18 The AESO's 2021 forecast ancillary services, losses and administrative costs have not, as of the date of filing this Update Application, been approved by the AESO's Board. The Budget Review Process moved through the first round of consultation with preliminary 2021 forecasts costs provided to stakeholders in October 2020. 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 December 2020.

19 Additional information on the AESO's business priorities and budget for 2021 is available on the AESO website at www.aeso.ca by following the path About the AESO ▶ Business planning and financial reporting ▶ Business plan and budget ▶ 2021.

2.2 Wires Costs

20 The 2021 forecast costs for wires are $1,951.6 million and represent approximately 82.4% of the AESO's transmission revenue requirement. Wires costs include primarily wires-related costs of TFOs as well as two small non-wires costs.

21 The AESO has determined the 2021 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,[10] approved in Decision 2010-606, referred to in Decision 2014-242[11] 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 cost 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.

22 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]

23 The majority of TFO tariff applications applicable to this Update Application have been filed and a number have been approved by the Commission or filed as a negotiated settlement.

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

2.3 Ancillary Services Costs

25 The forecast 2021 costs for ancillary services are $198.3 million and represent approximately 8.4% 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

[10] Exhibit 0026.00.AESO-2718, paras. 53-57.
[11] Decision 2014-242, para. 43.
[12] Decision 22093-D02-2017, *Alberta Electric System Operator 2017 ISO Tariff Update*, para. 37.
[13] Exhibit 0026.00.AESO-2718, para. 58.

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.

26 Ancillary service costs are primarily a function of volume forecasts and market-based commodity pricing forecasts. The 2021 forecast costs for ancillary services were based on a forecast average pool price of $53.93/MWh.

2.4 Losses Costs

27 The 2021 forecast costs for transmission line losses are $104.4 million and represent approximately 4.4% of the AESO's transmission revenue requirement as provided in Table 2-1 above. 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.

28 Losses costs are a function of volume forecasts and market-based commodity pricing forecasts. The 2021 forecast costs for losses were based on a forecast average pool price of $53.93/MWh.

2.5 Administrative Costs

29 The 2021 transmission-function forecast cost for administration is $114.5 million and represents approximately 4.8% of the AESO's transmission revenue requirement.

30 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;

31 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 *2021 Business Plan and Budget Proposal* allocates administrative costs among the three functions of the AESO; namely, transmission, energy market, and load settlement. The transmission-related portions of the AESO's administrative costs are included in the AESO's transmission revenue requirement detailed in Table 2.2-1 above.

3 2021 Rates Update

32 The 2021 rate calculations are included as Appendix B to this Update Application, in Tables B-1 through B-16.

33 The rate calculations use the following inputs:

(a) the 2021 forecast revenue requirement discussed in section 2 of this Update Application;

(b) the functionalization and classification of wires costs and the point-of delivery cost function approved for 2021 in Decision 22942-D02-2019;[14] and

(c) the 2021 forecast billing determinants prepared by the AESO.

3.1 Specific Rate Changes

34 Where applicable, rates in the ISO tariff have been updated to reflect the 2021 forecast revenue requirement, 2021 wires costs functionalization and classification, and 2021 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 DOS, *Demand Opportunity Service*;
- Rate XOS, *Export Opportunity Service*; and
- Rate XOM, *Export Opportunity Merchant Service*.

35 The levels for each of the above rates have been calculated in accordance with Appendix B to this Update Application. The updated rate sheets themselves are provided in the proposed 2021 ISO tariff included as Appendix D to this Update Application.

3.1.1 Rate PSC, Primary Service Credit

36 The 2021 primary service credit is calculated as:

- 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.

37 As the Rate DTS point of delivery charge has been updated in this Update Application, the AESO has correspondingly updated the primary service credit as provided in Table 3-1 below. The primary service credit amounts determined in Table 3-1 are reflected in Rate PSC included in Appendix B to this Update Application.

[14] Exhibit 22942-X0025, Appendix D, Transmission System Cost Causation Study 2018 Update dated September 14, 2017, page 5, Table D-5.

Table 3-1 – Calculation of 2021 Primary Service Credit

Rate Component	Rate DTS Charge	PSC Factor	Rate PSC Credit
Substation fraction	$14,860.00/month	79%	$11,739.00/month
First (7.5 × substation fraction) MW of billing capacity	$4,891.00/MW	79%	$3,864.00/MW
Next (9.5 × substation fraction) MW of billing capacity	$2,900.00/MW	79%	$2,291.00/MW
Next (23 × substation fraction) MW of billing capacity	$1,942.00/MW	79%	$1,534.00/MW
All remaining MW of billing capacity	$1,195.00/MW	100%	$1,195.00/MW

3.1.2 Regulated Generating Unit Connection Costs in Rate STS, Supply Transmission Service

38 The AESO most recently provided the derivation of the regulated generating unit[15] connection cost ("RGUCC") charge in an attachment to the AESO's response to information request AUC-AESO-009 in its 2014 ISO tariff application proceeding.[16] That attachment included a calculation of the RGUCC charge for each calendar year up to 2020, based on the original determinations of the Alberta Energy and Utilities Board (referred to below) which established the RGUCC. In general, RGUCC charges decrease every year reflecting the on-going amortization of connection costs over the lives of the previously-regulated generating units.

39 The RGUCC charge component of Rate STS only applies if a regulated generating unit terminates its system access service contract prior to the expiry of the regulated generating unit's base life as indicated in the tariff. As there is no regulated generating unit with a base life that extends past 2020[17], the AESO is proposing in this Update Application to remove the RGUCC provisions from the ISO tariff.

40 To remove the RGUCC charge, the AESO has proposed revisions, reflected in the blackline included as Appendix E to this Update Application, to the following provisions of the ISO tariff: subsection 3 of Rate STS; subsection 3(3) of Section 3;[18] subsection 3(3) of Section 9,[19] and Appendix A.

3.1.3 Rider J, Wind Forecasting Service Cost Recovery Rider

41 As the AESO explained in its 2014 ISO tariff application, Rider J, *Wind Forecasting Service Cost Recovery Rider* ("Rider J"), charges 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.[20] Since first being implemented in 2011, Rider J is expected to recover in 2021 all costs of the contracted wind forecasting service incurred to date.

42 On a cumulative forecast basis, the AESO will over collect $97,302 by the end of 2020. The wind forecasting service annual cost forecast for 2021 is $54,600. Annual wind powered generation metered

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[15] See Appendix A, Regulated Generating Units of the current ISO tariff.
[16] Exhibit 0109.03.AESO-2718, Attachment AUC-AESO-009.
[17] See Appendix A, Regulated Generating Units of the current ISO tariff.
[18] Subsection 3(3) of Section 3 of the current ISO tariff correlates to subsection 2.9(2) of Section 2 of the ISO tariff applied for in Proceeding 25175 (Exhibit 25175-X0116).
[19] Subsection 3(3) of Section 9 of the current ISO tariff correlates to subsection 5.3(3) of Section 5 of the ISO tariff applied for in Proceeding 25175 (Exhibit 25175-X0116).
[20] Exhibit 0026.00.AESO-2718, paras. 124-126.

energy forecast for 2021 is 5.7 million MWh, an increase of about 1.7 million MWh from 2019. The AESO proposes to set the Rider J charge at $0.00/MWh.

43 The proposed 2021 Rider J charge remains unchanged from the 2020 ISO tariff at $0.00/MWh. The 2020 ISO tariff rates became effective on April 1, 2020 and set Rider J at $0.00/MWh. From January to March 2020 the 2019 ISO tariff was in effect and the Rider J charge was $0.08/MWh. The amount collected for the first three months of 2020 was $126,772, which is sufficient to cover the cost of wind forecasting services for 2021. 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 2021.

Table 3-2 – Wind Forecasting Service Cumulative Balance

Line No.	Description	Actual 2010 – 2018	Actual 2019	Forecast 2020	Forecast 2021
1	Contracted wind forecasting service ($000)	$2,838.3	$304.6	$54.6	$54.6
2	Volumes (GWh)	28,563.2	4,005.8	5,661.8	5,661.8
3	Rider J Charge ($/MWh)	-	0.08	0.00	0.00
4	Revenue ($000)	$2,847.5	$320.5	$126.8	$0.0
5	Annual (undercollection) / overcollection ($000)	$9.2	$15.9	$72.2	($54.6)
6	**Cumulative Balance (undercollection) / overcollection ($000)**	**$9.2**	**$25.1**	**$97.3**	**$42.7**

44 The Rider J charge will not change from $0.00/MWh in the Update Application. The AESO will continue to monitor and report this amount in future tariff applications and updates.

3.2 2021 Forecast Billing Determinants

45 The rate calculations for the 2021 rates update are based on the AESO's forecast of billing determinants for 2021. 2021 billing determinants are estimated using historical and forecast ratios between DTS energy and each individual billing determinant listed below in Table 3-3. The updated DTS energy forecast, developed using a methodology similar to that applied to create the AESO's 2019 Long-Term Outlook 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 2019 Long-term Outlook*, including its data file, is available on the AESO website at www.aeso.ca by following the path Grid ▶ Forecasting. The billing determinants used in the 2021 rate calculations are also provided in Table B-12 of Appendix B to this Update Application.

46 Additionally, Table 3-3 below provides a comparison of the forecast billing determinants in this Update Application to the 2020 forecast billing determinants used in the 2020 ISO tariff update. Forecast coincident metered demand billing determinants for the 2021 forecast have increased by 0.4% compared to the 2020 forecast billing determinants. Forecast metered energy decreased by 4.5% and forecast billing capacity (which incorporates non-coincident metered demand, demand ratchets, and contract minimums) has decreased by 0.4%, with a 1.4% decrease in the first demand tier, a decrease of 1.2% in the second demand tier, a decrease of 0.6% in the third demand tier and an increase of 1.4% in the last demand tier.

Table 3-3 – 2021 and 2020 Forecast Billing Determinants

Rate DTS Billing Determinant	Units	2021 Forecast	2020 Forecast	Increase (Decrease) Amount	%
Coincident Metered Demand	MW-months	91,617.2	91,210.9	406.3	0.4%
Billing Capacity					
• Total Billing Capacity	MW-months	159,954.2	160,561.5	(607.3)	(0.4%)
• First (7.5×SF) MW	MW-months	36,754.8	37,281.1	(526.3)	(1.4%)
• Next (9.5×SF) MW	MW-months	34,657.9	35,072.1	(414.2)	(1.2%)
• Next (23×SF) MW	MW-months	43,642.5	43,920.9	(278.4)	(0.6%)
• All Remaining MW	MW-months	44,899.0	44,287.4	611.6	1.4%
Highest Metered Demand	MW-months	117,932.0	120,191.4	(2,259.4)	(1.9%)
Metered Energy (All Hours)	GWh	58,398.9	61,157.4	(2,758.5)	(4.5%)
DTS Market Participants	customer-months	5,387.0	5,477.6	(90.6)	(1.7%)
Pool Price	$/MWh	53.93	57.81	(3.88)	(6.7%)
Average Increase/(Decrease) Weighted by Revenue					**(0.7%)**

47 To further examine the reasonableness of the 2021 forecast billing determinants, Table 3-4 below provides a comparison of the forecast billing determinants in this Update Application to the 2016, 2017, 2018 and 2019 recorded billing determinants. The AESO considers that the overall decrease in billing determinants forecast for 2021 is reasonable considering that historically some of the billing determinants have been decreasing and impacts of COVID-19 are expected to continue in 2021. Energy usage and billing determinants have been negatively impacted by COVID-19 and low oil prices. The AESO posted a report on the impact of COVID-19 and low oil prices on June 29, 2020.[21]

48 The Highest Metered Demand billing determinant is forecast to decrease by 1.9% to reflect the decline in the billing determinant from 2018 to 2019. Preliminary analysis of this decline is associated with the additional behind-the-fence generation, increased transmission price responsive load, and slowing overall energy as evidenced by the decline in Metered Energy billing determinants from 2018 to 2019, as well as the potential impact of COVID-19 on 2021 billing determinants.

[21] An Update on the impact of COVID-19 and Low Oil Prices on Alberta's Power System: https://www.aeso.ca/assets/Uploads/Impact-COVID-Low-Oil-Update-June-29-2020.pdf

Table 3-4 – 2021 Forecast and 2019, 2018, 2017 and 2016 Recorded Billing Determinants

Rate DTS Billing Determinants	Units	2021 Forecast	2019 Recorded	2018 Recorded	2017 Recorded	2016 Recorded
Coincident Metered Demand	MW-months	91,617.2	93,436.3	95,806.9	94,486.6	92,111.9
Billing Capacity (Total)	MW-months	159,954.2	159,312.7	157,737.2	155,274.4	151,464.1
Highest Metered Demand	MW-months	117,932.0	120,522.7	121,845.0	120,536.9	115,502.5
Metered Energy (All Hours)	GWh	58,398.9	59,652.3	61,016.8	60,010.0	58,503.6
Market Participants (Total)	customer-months	5,387.0	5,407.4	5,285.1	5,283.2	5,255.7

49 Overall, the AESO considers that the 2021 forecast provides the best estimate, given the information available, of billing determinants for the rate calculations in this application.

3.3 Bill Impacts

50 As noted in section 2.2 of this Update Application, the AESO's 2021 forecast revenue requirement represents a decrease of $18.3 million (or 0.8%) from the total forecast costs for 2020. The decrease results from a forecast decrease of $60.1 million (or 23.3%) in ancillary services costs, which is partly offset by an increase of $35.6 million (or 1.9%) in wires costs.

51 At the same time, billing determinants have decreased from the 2020 forecast on which currently approved[22] rates are based. As a result, the AESO's 2021 updated rates represent an overall increase of 1.5% from the 2020 rates currently in place, including an increase of 1.6% to Rate DTS, and a decrease of 1.9% to Rate STS.

52 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.

53 The increases and decreases to the different components of Rate DTS are provided in Table 3-5 below. The Rate DTS increase of 1.6% represents a revenue-weighted average decrease over all components of Rate DTS.

54 Individual decreases 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.

55 To allow individual market participants to estimate the impact of the 2021 rates on their own Rate DTS bills, the AESO has included a bill impact estimator as Table B-13 in the rate calculations included as Appendix B to this Update Application. The bill impact estimator calculates bills for a given set of billing inputs under both the current 2020 Rate DTS and the updated 2021 Rate DTS, to allow the impact of the rates update on an individual service to be estimated.

[22] Decision 25175-D02-2020, *Alberta Electric System Operator 2020 ISO Tariff Update – Approved* (November 30, 2020).

Table 3-5 – Increase (Decrease) for 2021 Rate DTS Components

Rate DTS Charge	Unit	Proposed (1 Jan 2021)	Current (1 Apr 2020)	Increase (Decrease)
Bulk System				
• Coincident Metered Demand	$/MW	$11,085.00	$10,814.00	2.5%
• Energy	$/MWh	$1.22	$1.13	8.0%
Local System				
• Billing Capacity	$/MW billing	$2,893.00	$2,799.00	3.4%
• Energy	$/MWh	$0.93	$0.86	8.1%
Point of Delivery				
• Participant × SF	$/month	$14,860.00	$14,291.00	4.0%
• First (7.5 × SF) MW BC	$/MW	$4,891.00	$4,703.00	4.0%
• Next (9.5 × SF) MW BC	$/MW	$2,900.00	$2,789.00	4.0%
• Next (23 × SF) MW BC	$/MW	$1,942.00	$1,867.00	4.0%
• Remaining MW BC	$/MW	$1,195.00	$1,150.00	4.0%
Operating Reserve	% of Pool Price	6.19%	7.13%	(13.2%)
Transmission Constraint Rebalancing Charge	$/MWh	$0.002	$0.002	0.0%
Voltage Control	$/MWh	$0.01	$0.05	(80.0%)
Other System Support	$/MW	$25.00	$24.00	4.2%
Net Change (revenue weighted)				**1.6%**

56 The changes to the different components of Rate STS are provided in Table 3-6 below. The Rate STS decrease of 1.9% represents a revenue-weighted average decrease over all components of the rate.

57 Individual decreases or increases experienced by market participants will vary, depending on the specific characteristics of a market participant's system access service, including whether it includes a previously-regulated generating unit subject to the RGUCC charge. The RGUCC charge expires at the end of 2020 and, as discussed in section 3.1.2 above, is being proposed to be removed from the ISO tariff.

Table 3-6 – Increase (Decrease) for 2021 Rate STS Components

Rate STS Charge	Unit	Proposed (1 Jan 2021)	Current (1 Apr 2020)	Increase (Decrease)
Losses	% of Pool Price	2.98%	3.01%	(1.0%)
RGU Connection Costs	$/MW	$0.00	$15.00	(100.0%)
Net Change (revenue weighted)				**(1.9%)**

58 In particular, the AESO notes that the loss factors provided in Table 3-6 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*, as specified in Rate STS. Section 501.10 of the ISO rules was confirmed by the

Commission in Decision 790-D05-2016[23] in Proceeding 790, although the AESO notes that the losses charge remains as approved on an interim basis in Commission Decision 2014-242.[24]

4 Maximum Investment Levels Update

59 The tariff update approach described in section 2 of this Update Application includes updating investment amounts approved in the Decision[25] to revise the existing point-of-delivery cost curve to Option #2[26] and reflecting an escalation factor based on a composite of specified recent inflation indices.

60 The AESO has accordingly updated the composite inflation index used for developing the point of delivery cost function to 2021, using additional Statistics Canada cost index values and the most recent Conference Board of Canada forecast of the Alberta consumer price index. Table 4-1 below provides the composite inflation index values for 2018, 2019, 2020 and 2021, as included in the 2018 ISO tariff filing, and for 2021 as updated in this application.

Table 4-1 – Escalation Factor for Composite Inflation Index

	Year	Basis	Present Value Factor
2018 Tariff Application	2018	Forecast	1.6885
2019 Tariff Update	2019	Forecast	1.6367
2020 Tariff Update	2020	Forecast	1.6814
2021 Tariff Update	2021	Forecast	1.7206
2021 Escalation Factor (over 2018)	1.7206_{2021} / 1.6885_{2018} =		1.0641

61 The resulting escalation factor for updating the 2021 maximum investment levels in section 8[27] of the ISO tariff is 1.0641, 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.

62 The AESO has applied the resulting 1.0641 escalation factor to the 2018 Rate DTS maximum investment levels to determine the 2021 Rate DTS maximum investment levels, as summarized in Table 4-2 below. Table 4-2 also includes the calculation of the corresponding Rate PSC maximum investment levels for each year.

[23] 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.
[24] Decision 2014-242, para. 730.
[25] Decision 22942-D02-2019, para 201.
[26] Exhibit 22942.0018.03, Appendix G – Options for POD Cost Function Workbook, Tab 'Option 2 Investment Proposed', Cells C11 to G11.
[27] Set out in Section 8 of the current ISO tariff, and Section 4 of the ISO tariff applied for in Proceeding 25175 (Exhibit 25175-X0116).

Table 4-2 – Calculation of 2021 Maximum Investment Levels

Tier	Rate DTS Investment	PSC Factor	Rate PSC Investment
2018 Maximum Investment Levels			
Substation fraction (for new points of delivery only)	$100,400/year	21%	$21,080/year
First (7.5 × substation fraction) MW of contract capacity	$33,050/MW/year	21%	$6,940/MW/year
Next (9.5 × substation fraction) MW of contract capacity	$19,600/MW/year	21%	$4,120/MW/year
Next (23 × substation fraction) MW of contract capacity	$13,150/MW/year	21%	$2,760/MW/year
All remaining MW of contract capacity	$8,050/MW/year	0%	$0/MW/year
2021 Escalation Factor (over 2018)	**1.0473**		
2021 Maximum Investment Levels			
Substation fraction (for new points of delivery only)	$106,850/year	21%	$22,440/year
First (7.5 × substation fraction) MW of contract capacity	$35,150/MW/year	21%	$7,380/MW/year
Next (9.5 × substation fraction) MW of contract capacity	$20,850/MW/year	21%	$4,380/MW/year
Next (23 × substation fraction) MW of contract capacity	$14,000/MW/year	21%	$2,940/MW/year
All remaining MW of contract capacity	$8,550/MW/year	0%	$0/MW/year

5 Generating Unit Owner's Contribution Rates

63 As part of the AESO's 2018 comprehensive ISO tariff application (the "2018 Application"),[28] the AESO proposed to include the rates for a generating unit owner's contribution ("GUOC") as part of the ISO Tariff (rather than as part of a separate document posted to the AESO's website, which had been the practice to that point). The GUOC rates proposed by the AESO in the 2018 Application were approved by the Commission in Decision 22942-D02-2019.[29]

64 To date, planning and engineering studies have not demonstrated a need to update the GUOC rates proposed by the AESO in the 2019 Application. Accordingly, the AESO proposes that the GUOC Rates remain unchanged from those proposed in the 2018 Application, as follows:

[28] Exhibit 22942-X0163, para. 299.
[29] Decision 22942-D02-2019, para. 323.

Table X.X – 2021 Generating unit owner's contribution rates

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

6 Conclusion

65 Based on all of the foregoing, the AESO submits that the tariff updates proposed in this Update Application are just and reasonable, and comply with the update methodology approved by the Commission for the ISO tariff in Decision 2010-606.[30] The AESO respectfully requests that the Commission approve this Update Application with effect as of January 1, 2021, including (i) the updated amounts included as Appendix B to this Update Application, (ii) the proposed 2021 ISO tariff Rate DTS, Rate FTS, Rate DOS, Rate XOS, Rate XOM, Rate PSC, Rate STS, Rider J and Section 8[31] included as Appendix D to this Update Application, and (iii) the revisions to the terms and conditions of the ISO tariff set out in Appendix D to this Update Application, required to remove reference to the RGUCC charge. The AESO further requests that the Commission issue its approval on or before December 28, 2020, as this is the last approval date that will allow the proposed tariff updates to be implemented by the AESO effective January 1, 2021 on a prospective basis. If the timing of this application does not permit the granting of final approval on or before December 28, 2020, the AESO requests that the Commission approve this application on an interim refundable basis.

66 All of which is respectfully submitted this 12th day of November 2020.

Alberta Electric System Operator

Per: Miranda Keating Erickson
Vice-President, Markets

[30] Decision 2010-606, paras. 536-545.

[31] Set out in Section 8 of the current ISO tariff, and Section 4 of the ISO tariff applied for in Proceeding 25175 (Exhibit 25175-X0116).