Alberta Electric System Operator 2018 ISO Tariff Compliance Filing Pursuant to Decision 22942-D02-2019 and 2020 ISO Tariff Update Application

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1 Introduction

1 On September 22, 2019, the Alberta Utilities Commission ("Commission") issued Decision 22942-D02-2019 ("Decision") regarding the Alberta Electric System Operator's ("AESO's") 2018 comprehensive Independent System Operator ("ISO") tariff application ("Application").

2 This compliance filing responds to compliance filing directions issued in the Decision, which ordered the AESO to refile the Application to reflect the findings, conclusions and directions in the Decision after January 1, 2020 but no later than January 31, 2020 ("Compliance Filing").

3 Pursuant to sections 30 and 119 of the *Electric Utilities Act*, S.A. 2003, c. E-5.1 ("Act"), the AESO also seeks approval of the AESO's 2020 Update Application to update the rates for the 2020 ISO tariff ("Update Application"). As detailed further below, this annual tariff update seeks approval of changes to the rates to be charged by the AESO in 2020 for system access service and to the maximum investment levels provided under section 4 of the ISO tariff.

4 The Update Application, if granted, would change the levels (that is, the dollar-based and percentage of pool price amounts) included in the rates, Subsection 4.7(2)(b), and Subsection 7.3(1) of the ISO tariff approved in the Decision, based on costs and billing determinants forecast by the AESO for the 2020 calendar year. The Update Application also includes changes resulting from the Commission's acceptance of the 2018 Transmission Cost Causation Study results in the Decision.[1] The Update Application does not include any changes to the structure of the rates.

1.1 Organization of Application

5 This compliance filing is organized into the following sections:

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

2 **Compliance With Refiling Directions issued in Decision 22942-D02-2019** — Provides a response to each refiling direction in the Decision.

3 **Additional Revisions to the Terms and Conditions of the Refiled ISO Tariff**

4 **2020 ISO Tariff Update Application** – Provides background, summarizes the AESO's forecast 2020 revenue requirement, discusses the calculation of rate levels, and discusses the calculation of 2020 maximum investment levels.

5 **Conclusion**

Appendix A Refiled ISO Tariff (2020 ISO Tariff).

Appendix B Blackline of Refiled ISO Tariff and Applied-for 2018 ISO Tariff.

Appendix B.1 Blackline of Refiled ISO Tariff Rates and Investment Levels, and currently effective 2019 ISO Tariff.

[1] Decision 22942-D02-2019, *Alberta Electric System Operator*, *2018 Independent System Operator Tariff* (September 22, 2019) ("**Decision**"), para. 74.

Appendix C AESO 2020 Business Plan and Budget Proposal — Document prepared by AESO management in consultation with stakeholders, as submitted to the AESO Board on January 15, 2020 containing the AESO's proposed 2020 business initiatives and proposed 2020 budgets and forecasts for ancillary services costs, transmission line losses costs, and administrative costs.

Appendix D 2020 Rate Calculations — Microsoft Excel workbook which calculates the updated dollar and percentage of pool price amounts for the 2020 rates.

Appendix E 2020 Escalation Factor and Investment Levels — Microsoft Excel workbook which calculates the composite inflation index and escalation factor used to update maximum investment levels.

Appendix F 2020 Bill Impact Analysis — Microsoft Excel workbook which provides the analysis on market participants' bills of the Rate DTS changes proposed in this application resulting from changes to the revenue requirement, billing determinants and the approved changes resulting from the Decision.

1.2 Relief Requested

6 For the reasons detailed further in the remainder of this Compliance Filing and Update Application, respectively, the AESO seeks the following relief pursuant to sections 30 and 119 of the Act and in accordance with the orders and directions set out in the Decision:

(a) confirmation that the Commission's refiling directions in the Decision have been satisfactorily responded to in this Compliance Filing; and

(b) approval of the refiled ISO Tariff (2020 ISO Tariff), provided as Appendix A to this Compliance Filing (the "Refiled ISO Tariff"), including (i) the updated amounts included in Appendix D to this Compliance Filing, and (ii) the proposed 2020 ISO tariff Rate DTS, Rate FTS, Rate DOS, Rate XOS, Rate XOM, Rate PSC, Rate STS, Rider J, Subsection 4.7(2)(b), and Subsection 7.3(1) included in Appendix A to this Compliance Filing.

7 The AESO requests that the Refiled ISO Tariff be made effective no earlier than the first day of the month at least 30 days after the date of the Commission's decision regarding the Refiled ISO Tariff to allow adequate time to implement the ISO tariff.

8 The AESO further requests that the Update Application be approved on an interim refundable basis no later than March 1, 2020 and effective no later than April 1, 2020 in order to minimize amounts recovered or refunded through Rider C, *Deferral Account Adjustment Rider*, reduce deferral account balances, and potentially reduce amounts transferred between market participants in future deferral account reconciliations.

2 Compliance with Refiling Directions issued in Decision 22942-D02-2019

9 The AESO's responses to the refiling directions issued in the Decision are set out below and reflected in the Refiled ISO Tariff. A blackline of the Refiled ISO Tariff and the applied-for 2018 ISO tariff filed by the AESO in Proceeding 22942[2] is included as Appendix B to this Compliance Filing.

Direction 3

Provide further support for a change to the existing power factor deficiency charge from $400 to $1,200 per MVA

Direction

"Given these concerns, the AESO's proposed change to the existing power factor deficiency charge to $1,200 per MVA from $400 per MVA is denied. The Commission agrees with the AESO that an increase to the charge is required, but the Commission has not been persuaded by the AESO that an increase to $1,200 per MVA is the appropriate amount. Considering this finding, the AESO's proposal to index the power factor deficiency charge to the weighted average increase in transmission system costs is also denied. The AESO is directed to either provide further support for its calculation of the $1,200 per MVA charge in the compliance filing to this decision or in its next comprehensive GTA." [Paragraph 254 of the Decision]

Response

The AESO intends to provide further support for its calculation of the $1,200 MVA charge in its 2020 comprehensive ISO tariff application ("2020 Tariff Application"). The AESO's proposed timing and approach to the 2020 Tariff Application is addressed in the AESO's response to Direction 22, below.

Direction 6

Update the AESO's proposed 2018 ISO tariff to reflect the finding that the AESO's request to extend Rider A1 for an additional 20 years is denied

Direction

"For all of the above reasons, the AESO's request that Rider A1 be extended for an additional 20 years to 2041 is denied. The AESO is directed to update its proposed 2018 ISO tariff to reflect this finding in its refiling." [Paragraph 313 of the Decision]

Response

The AESO has revised Rider A1 of the Refiled ISO Tariff to comply with this direction.

[2] Exhibit 22942-X0014.03

Direction 7

AESO to clarify whether subsection 7.3(1)(b) is still required for GUOC calculation, given the Commission's decision with respect to the E.L. Smith Solar Power Plant

Direction

"The Commission approves the AESO's proposed method to calculate the GUOC rate, and the AESO's GUOC rates, included in Table 10 above. However, in its refiling to this decision, the Commission directs the AESO to clarify whether part (b) of the capacity used to calculate a GUOC is still required, given the Commission's decision with respect to the E.L. Smith Solar Power Plant (Decision 23418-D01-2019)." [Paragraph 323 of the Decision].

Response

The AESO has revised subsections 7.2 and 7.3 of the Refiled ISO Tariff to comply with this direction. As stated by the AESO in the AESO's Amended 2018 Comprehensive ISO tariff Application, the intention of revising the capacity used to calculate a GUOC is to ensure that market participants with generation pay an appropriate amount of a GUOC contribution:

> This change would result in transmission connected dual-use connections and distribution connected market participants with generation having to pay an appropriate amount of a GUOC contribution. Any additional generation capacity specified in (a) or (b) would either reduce inflows or increases outflows from its location. The AESO plans to accommodate the connection of generation capacity specified in (a) or (b) above so, therefore, it is appropriate that a GUOC contribution rate be based on generation capacity specified in (a) or (b).[3]

In the AESO's view, proposed part (b) of the capacity used to calculate a GUOC[4] is no longer needed as a result of the Commission's conclusions in Decision 23418-D01-2018[5] and subsequent decisions[6] regarding the issue of self-supply and export of excess electric energy. Notably, the Commission found that, absent any exemption provided by the statutory scheme, market participants must provide all electric energy generated by a power plant to the power pool and AIES.[7] This finding renders proposed part (b) irrelevant as the capacity of the generation connection must be reflective of the amount of electric energy that the generating facility will offer to the power pool (i.e. maximum capability).

Revised subsection 7.2 of the Refiled ISO Tariff specifies that a GUOC should be calculated based on the maximum capability of the generating facility. Subsection 7.3 has been deleted because, with the deletion of part (b), it would be redundant to revised subsection 7.2.

[3] Exhibit 22942-X0163, Amended Application, para 301.
[4] Decision, para 316.
[5] Decision 23418-D01-2019, E.L. Smith Solar Power Plant (February 20, 2019).
[6] Decision 24393-D01-2019, International Paper Canada Pulp Holdings ULC Request for Permanent Connection Order for 48-Megawatt Power Plant (June 6, 2019); and Decision 24126-D01-2019, Cynthia Gas Plant Power Plant (June 25, 2019) (**Decision 24126-D01-2019**).
[7] Decision 24126-D01-2019, para 38.

Direction 8

Revise subsection 5.2(2) to clarify that it will not apply to deviations below 10 per cent, that any proposed adjustments by the AESO must first be discussed with the market participant, and to directly refer to dispute resolution process

Direction

"The Commission directs the AESO to amend subsection 5.2(2) to include wording that this subsection will not apply to deviations below 10 per cent, that any proposed adjustments by the AESO must first be discussed with the market participant, and that a direct reference to the sections of the dispute resolution process that can be utilized by market participants regarding any disputes that may arise under this provision of the terms and conditions be provided." [Paragraph 416 of the Decision]

Response

The AESO has revised subsection 5.2(2) of the Refiled ISO Tariff to comply with this direction.

Direction 12

Revise subsection 4.10 to ensure adequate discretion to vary application of certain aspects of ISO tariff contribution policy

Direction

"The Commission agrees with EDTI that by excluding the phrase, "including the determination of costs to be system-related in certain circumstances that might, under strict application of the customer contribution provisions, have been classified as participant-related," the AESO's proposed subsection 4.10 may not provide adequate discretion to the AESO to vary the application of certain aspects of its tariff contribution policy when circumstances warrant. Accordingly, the Commission directs the AESO to revise its proposed subsection 4.10 at the time of its refiling application to substantially replicate the wording in the current tariff's subsection 8.10." [Paragraph 525 of the Decision]

Response

The AESO has revised subsection 4.10(3) of the Refiled ISO Tariff to comply with this direction.

Direction 15

Provide a complete explanation of its understanding of the effect on the U of A of its adjusted metering practice

Direction

"The Commission, as an expert tribunal, employs a rigorous procedural process in its determination of applications before it. In doing so, it also recognizes that tribunals are created to increase the efficiency of the administration of justice. Therefore, in order to consider this matter expeditiously, notwithstanding the usual scope associated with a compliance filing, the Commission directs the AESO to provide a complete explanation of its understanding of the effect on the U of A of its adjusted metering practice at the time of its refiling application. The U of A will be permitted to file evidence in this refiling application in response to the AESO's filing."

[Paragraph 843 of the Decision]

Response

As noted by the AESO in Proceeding 22942, "the AESO is not proposing that the adjusted metering practice be applied to existing sites that are already metered on a gross basis.[8] In accordance with the AESO's proposal, the University of Alberta's existing load and generation configuration would not be impacted by implementation of the adjusted metering practice.[9]

The AESO's statement that the University of Alberta's existing configuration would not be impacted is further supported by the Commission's findings on (and approval of) the AESO's grandfathering proposal for the adjusted metering practice. Specifically, the Commission found that the AESO's grandfathering proposal to be a reasonable approach, which allows existing DCG proponents to continue to operate under the regime under which these proponents initially brought forward their generation projects.[10] The approved adjusted metering practice will be applied commencing with the effective date of the Refiled ISO Tariff and therefore, the University of Alberta's existing load and generation configuration will be exempt from application of the adjusted metering practice.

If a SASR is submitted in relation to the existing University of Alberta load and generation configuration, then the adjusted metering practice would apply as per subsection 3.6(4) of the Refiled ISO Tariff.

Directions 16 and 17

Totalized billing of industrial complexes

Directions

"In its compliance filing the AESO is directed to file any changes that are necessary to the ISO tariff to comply with the Commission's findings in [Section 7.5 of the Decision]." [Paragraph 873 of the Decision]

"Because the AESO's revised position on this issue was brought forward in argument, the Commission does not have enough information to make determinations with respect to other exemptions or approvals for dual-use customers or industrial complexes. If there are other issues regarding the metering of industrial complexes and specific exemptions or approvals available to industrial complexes, the AESO is directed to identify these and, if necessary, propose and justify amendments to its tariff in its compliance filing.'' [Paragraph 874 of the Decision]

Response

At Section 7.5 of the Decision, the Commission made the following findings:

- That the principles established in Decision 23418-D01-2019, regarding the E.L. Smith Solar Power Plant, were applicable to Proceeding 22942. [Paragraph 869 of the Decision]
- That industrial complexes that have not obtained an exemption under Section 4 of the Hydro and Electric Energy Act must be gross metered. [Paragraph 870 of the Decision]

[8] Exhibit 22942-X0578, AESO Reply Argument, para. 21.
[9] Exhibit 22942-X0578, AESO Reply Argument, para 70.
[10] Decision, para 796.

- That totalization or net metering at a substation is only permissible for Commission-designated industrial systems. [Paragraphs 870 and 872 of the Decision]

The AESO has revised subsection 3.2(2)(f) and subsection 3.6(4)(a) of the Refiled ISO Tariff to clarify that, on a go-forward basis, totalized metering at a substation is only permissible for industrial systems that have obtained a designation from the Commission or in circumstances where a market participant has otherwise obtained an approval from the Commission that permits the export to the interconnected electric system of electric energy in excess of the market participant's own requirements (as could occur, for instance, pursuant to section 95(8) of the Act for a municipality or subsidiary of a municipality). The AESO considers these revisions to be consistent with the principles established in Decision 23418-D01-2019 and the Commission's findings in Section 7.5 of the Decision. The AESO has not identified any other amendments to be necessary as a result of the Commission's findings or directions in Decision 23418-D01-2019 or Section 7.5 of the Decision.

Direction 18

File a joint proposal for implementation of AltaLink's contribution proposal

Direction

"Accordingly, the Commission directs the AESO, in its refiling, to consult with AltaLink and for the AESO and AltaLink to provide a joint proposal for the implementation of AltaLink's contribution proposal." [Paragraph 1079]

Response

On October 25, 2019, in response to a request by FortisAlberta Inc. in Proceeding 24932,[11] the Commission issued a stay of Section 8 of the Decision, which includes Direction 18.[12] In light of the stay, the AESO is not providing a response to Direction 18 in this Compliance Filing. The AESO will respond to Direction 18, if required, following the lifting of the stay and the Commission's determination of the matters currently before it in Proceeding 24932.

Direction 21

Review and revise all proposed changes to terms and conditions and amend to reflect the Commission's denial of the AESO's proposal whereby "transmission direct connected distribution customers", rather than Fortis, would execute a construction commitment agreement directly with AltaLink

Direction

"However, the Commission does not accept the AESO's proposal to change the terms and conditions to adopt a proposal by AltaLink and Fortis and described in subsection 7.8.4 of the amended application whereby "transmission direct connected distribution customers, rather than Fortis, would execute a construction commitment agreement directly with AltaLink. In conjunction with this proposal, the AESO outlined certain changes to the wording of certain proposed terms and conditions that would be required to implement this change in Table 7-2 of the amended application.

[11] Exhibit 24932-X0012, para. 75.
[12] Exhibit 24932-X0041.

... In light of the above, the Commission directs the AESO to review all of the proposed changes to its terms and conditions in Table 7-2 and to apply any required amendments necessary to reflect the Commission's finding in this section at the time of its refiling application." [paragraphs 1172-1174]

Response

In accordance with the Commission's direction, the AESO has revised the proposed subsections referred to in Table 7-2 of the AESO's amended 2018 comprehensive ISO tariff application.[13] Specifically, proposed subsections 3.5(1), 3.5(2), 4.6(2), 6.2(2), 6.5(1)-(2), 6.5(3), 6.6(1)-(2), 6.6(4)-(7), 6.7(1)-(2), and 6.8(1)-(5) of the Refiled ISO Tariff. Although listed in Table 7-2, the AESO has not made any revisions to subsection 6.2(1) of the Refiled ISO Tariff as a result of this direction, because subsection 6.2(1) as currently worded does not contemplate that the legal owner of a transmission facility and a direct-connect distribution customer would be dealing with each other directly. Instead, this provision simply states that the market participant requesting system access service must ensure that it meets the financial obligation described in the provision.

Direction 22

Assess ability to file a comprehensive tariff application before the end of the first quarter of 2020

Direction

"Given the foregoing, the Commission directs the AESO to assess its ability to prepare a comprehensive tariff application before the end of the first quarter of 2020 in light of the findings and directions in this decision. If the AESO considers that the existing deadline is not achievable, the Commission directs the AESO to so advise and propose an alternate deadline in its compliance filing pursuant to this decision." [Paragraph 1213]

Response

The existing deadline to file the AESO's next comprehensive tariff application before the end of the first quarter of 2020 is not achievable. The directions issued in the Decision related to the next comprehensive tariff application, in combination with the significant degree of tariff-related consultation currently being undertaken by the AESO, mean that the AESO will not be able to file its next comprehensive application until later in 2020. The AESO advises the Commission that it intends to take a phased approach to the filing of its next comprehensive tariff application, based on the phases and schedule described below. Consequently, the AESO requests that the Commission extend the deadline for the filing of the AESO's next comprehensive ISO tariff application to the end of the third quarter of 2020.

Additionally, following the next comprehensive tariff application, the AESO intends to modify the initial phased approach to propose structural tariff changes on an "as needed" basis rather than as part of a comprehensive application that the AESO currently files on a 3 or 4 year cycle in accordance with the approach accepted by the Commission in Decision 2010-606.[14] The AESO considers that a phased approach will allow issues to be considered and consulted upon with greater efficiency than the current approach of filing comprehensive tariff applications that bundle

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[13] Exhibit 22942-X0163 at PDF 80.

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

and address multiple significant issues within a single application, and will also allow the AESO to address required tariff changes in a more agile and adaptable manner in response to industry change. Under the phased approach, routine tariff update applications involving the following three principal components would continue to be filed by the AESO on an annual basis:

- An annual revenue requirement update, plus forecast for ancillary service costs, losses costs and administration costs approved by the AESO Board for the forecast year;
- Revised rate levels for each AESO rate calculated from the forecast revenue requirement and forecast billing determinants using rate calculations and rate design approved in the Decision;
- Revised Generating Unit Owner Contribution rates as assessed and updated using the methodology discussed in the 2018 ISO tariff filing;[15] and
- Annual updates to investment amounts approved in the most recent comprehensive tariff reflecting an escalation factor abased on the most recent Conference Board of Canada Alberta consumer price index (CPI).

To accommodate ongoing tariff consultation, as well as resources required for other upcoming or ongoing tariff-related proceedings,[16] the AESO intends to address the following matters in its 2020 Tariff Application in accordance with the following schedule:

- Phase 1 - Bulk and Regional Tariff Design (Direction 1 from the Decision[17]) - no later than September 30, 2020;
- Phase 2 - Contribution Policy including the POD cost function (Direction 2 from the Decision),[18] system vs. connection project criteria (Direction 13 from the Decision),[19] "grey area" system projects (Direction 14 from the Decision),[20] and optional facilities/good electric industry practice (Direction 19 from the Decision),[21] - no later than December 31, 2020; and
- Phase 3 - Power factor deficiency charge (Directions 3 and 4 from the Decision),[22] contract level adjustments (Directions 9 and 10 from the Decision),[23] connection alternatives, SASR requirements (Direction 11 from the Decision),[24] and relocation principles (Direction 20 from the Decision)[25] - no later than March 31, 2021.

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[15] Exhibit 22942-0163, para. 306.
[16] Including the AESO's upcoming 2020 ISO tariff deferral account reconciliation application, anticipated to be filed in Q2 2020; the Commission's ongoing distribution system inquiry (Proceeding 24116); and the ongoing proceedings and related technical session process resulting from the review and variance applications submitted by the Community Generation Working Group and FortisAlberta Inc. (Proceedings 25101 and 25102, respectively).
[17] Decision, para. 74.
[18] Decision, para. 202.
[19] Decision, para. 1139.
[20] Decision, para. 608.
[21] Decision, para. 607.
[22] Decision, paras. 254 and 258.
[23] Decision, paras. 418 and 442.
[24] Decision, para. 462.
[25] Decision, para. 1152.

3 Additional revisions to the terms and conditions of the Refiled ISO Tariff

1.1 3.1 Adjusted Metering Practice - Grandfathering

10 The Commission in the Decision approved the adjusted metering practice proposed by the AESO, and found the AESO's implementation and grandfathering proposal with respect to the adjusted metering practice to be reasonable.[26]

11 The requirements of the adjusted metering practice were set out at subsections 3.6(2) and (3) of the applied-for 2018 ISO tariff and these subsections remain unchanged in the Refiled ISO Tariff. However, to fully codify the adjusted metering practice within the Refiled ISO Tariff, the AESO has revised subsection 3.6(4) to explicitly incorporate its grandfathering proposal. In particular, subsection 3.6(4) has been revised to provide for grandfathering as follows:

- in subsection 3.6(4)(b), to clarify that connection projects that require the construction of transmission facilities will be grandfathered if, prior to the effective date of the Refiled ISO Tariff: (i) permit(s) & licence(s) have been issued by the Commission for the connection project, and (ii) as determined by the ISO, construction of the market participant's load or generation facilities has materially commenced;
- in subsection 3.6(4)(c), to clarify that connection projects that do not require the construction of transmission facilities will be grandfathered if, prior to the effective date of the Refiled ISO Tariff: (i) where the connection project is required to serve generation facilities, a power plant approval has been issued by the Commission for which system access service under Rate STS is required, and (ii) as determined by the ISO, construction of the market participant's load or generation facilities has materially commenced; and
- in subsection 3.6(4)(d), to clarify that connection projects that will proceed by way of a connection to a substation that serves existing distributed generation will also be grandfathered.

12 Subsections 3.6(4)(b) and (c) of the Refiled ISO Tariff are consistent with the grandfathering that was described and proposed by the AESO in Information Document 2018-019T, *Determination of Rate STS, Rate DTS and Metering Levels for a DFO* (the "Metering ID") and in the AESO's written evidence and testimony in Proceeding 22942.

13 In contrast, subsection 3.6(4)(d) represents a new circumstance that has been identified by the AESO since Proceeding 22942, and for which the AESO considers grandfathering to also be appropriate. Specifically, where a new distributed generator connects to a substation that already serves existing or grandfathered distributed generation, it would not be technically feasible to simultaneously apply the adjusted metering practice to the new distributed generator while grandfathering the existing distributed generator. Grandfathering in this manner will continue some degree of billing determinant erosion. However, in these circumstances, the AESO notes that if a sufficient amount of distributed generation connects at a substation (such that the supply from the distributed generation at the substation exceeds the load served at the substation), there will be no difference between metering on either a net basis (as per the existing metering

[26] Decision, para. 844.

practice) or a gross basis (as per the adjusted metering practice). The AESO therefore considers grandfathering in these circumstances, at a substation level, to be required.

14 With the Commission's approval of subsections 3.6(4)(b)-(d), the AESO considers the Metering ID to no longer be required and would revoke it concurrently with the Refiled ISO Tariff coming into effect.

3.2 Administrative revisions and clarifications

15 In addition to the revisions identified in this Compliance Filing that arise out of the Commission's directions and the revisions related to the adjusted metering practice referred to above, the AESO has made the following administrative (i.e., non-substantive) revisions to the terms and conditions of the Refiled ISO Tariff, for the purposes improving clarity, as follows:

- Revision histories have been updated;
- Subsection3.3(4) has been revised to clarify that, if the construction of transmission facilities is not required in response to a system access service request, a market participant will be required to comply with either the AESO's behind the fence or contract change process (as applicable);
- Subsection 3.6(9) has been revised to clarify that it is the owner of a generating facility rather than the market participant requesting system access service that must provide evidence of funds sufficient to pay the generating unit owner's contribution;
- Subsection 4.2(4) has been revised to ensure it is the costs of incremental transmission facilities that are classified as participant-related, not the facilities themselves;
- Subsection 4.6(4) has been removed as it is unnecessary given subsection 7.4(1), which already requires the generator facility owner to pay the generating unit's owner contribution;
- Subsection 7.4(4) has been revised to clarify that, for a generator facility connection that does not require the construction of transmission facilities, the generating unit owner's contribution must be paid at the time that the applicable Rate STS contract becomes effective;
- The header above subsection 10.3 has been revised to 'Totalized Billing at Separate Substations', given that this provision is only intended to apply to totalized billing between separate substations (not, for instance, between services at a single substation). Additionally, subsection 10.3 has been revised to clarify that totalized billing between substation may apply regardless of whether a waiver has been granted under subsection 101(2) of the Act;
- The phrase "as of the Effective Date" has been removed from the execution page of pro forma system access service agreements set out in Appendix B of the Refiled ISO Tariff, given that these agreements could (per the Refiled ISO Tariff) be executed prior to the effective date; and
- Rider F, *Balancing Pool Consumer Allocation Rider*, has been updated in accordance with Decision 24982-D01-2019, issued on November 25, 2019.

4 2020 ISO Tariff Update

4.1 Background

16 As noted above, this Update Application consists of formulaic updates to: (i) the AESO's annual revenue requirement, based on the AESO's updated forecast costs for 2020; (ii) rate, rider, and maximum investment level amounts using the rate calculation methodology approved by the Commission in the Decision;[27] and (iii) the investment amounts approved in the Decision,[28] in accordance with the escalation factor described below. In the AESO's view, the ISO tariff updates proposed in this Update Application will limit potential misallocations that might occur if the AESO continued to rely on Rider C, *Deferral Account Adjustment Rider*, to allocate revenue and cost imbalances to market participants.

17 This Update Application is consistent with the tariff update methodology accepted by the Commission in Decision 2010-606.[29]

4.2 AESO 2020 Forecast Revenue Requirement

18 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 2020 are detailed in column A of Table 4.2-1. For comparison, Table 4.2-1 includes costs in the AESO 2020 Business Plan and Budget Proposal (Dated January 15, 2020) for 2020 (included as Appendix C to this application), updated forecast costs for 2019,[30] forecast costs for 2019,[31] and the recorded costs for 2018 and 2017, in columns B, C, D, and E, respectively.

Table 4.2-1 – 2020 Forecast, 2019 Updated Forecast and Forecast, 2018 and 2017 Recorded Cost Components

Cost Component	2020 Forecast ($ 000 000) A	2019 Updated Forecast ($ 000 000) B	2019 Forecast ($ 000 000) C	2018 Recorded ($ 000 000) D	2017 Recorded ($ 000 000) E
Wires	1,916.7	1,846.8	1,834.6	1,782.5	1,743.7
Ancillary services	257.8	313.8	313.8	277.8	115.0
Losses	113.5	126.1	126.1	97.1	50.4
Administrative	99.0	97.6	97.6	104.5	98.9
Revenue Requirement	**2,387.0**	**2,384.3**	**2,372.1**	**2,261.9**	**2,008.0**

Note: Numbers may not add due to rounding

19 The 2020 forecast costs represent an increase of $15.0 million (or 0.6%) over the 2019 forecast costs included in the 2019 ISO tariff update application. The increase results from a forecast

[27] Decision, para. 74.
[28] Decision, para. 201.
[29] Decision 2010-606, paras. 536-545.
[30] 2019 Updated Forecast includes 2019 forecast costs and updated wires costs reflecting recent TFO filings, compliance filings and decisions for 2019.
[31] 2019 Forecast reflects amounts applied for in AESO's 2019 ISO tariff update application, approved in Decision 24036-D01-2018, *Alberta Electric System Operator 2019 Independent System Operator Tariff Update* (December 18, 2018) (**Decision 24036-D01-2018**).

increase of $82.1 million (or 4.5%) in wires costs with a forecast decrease of $56.0 million (or 17.8%) decrease in ancillary services costs.

20 The 2019 updated forecast costs represent an increase of $12.2 million (or 0.5%) over the 2019 forecast costs included in the 2019 ISO tariff update application. The increase results from a forecast increase of $12.2 million (or 0.7%) in wires costs.

4.2.1 AESO Board Approval of Costs

21 The AESO is not seeking approval in this application of its 2020 forecast revenue requirement. The AESO's forecast costs are approved through other processes provided for in relevant legislation. These costs, as provided in column A of Table 4.2-1, were addressed in the AESO *2020 Business Plan and Budget Proposal* dated January 15, 2020, included as Appendix C to this application.

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

(a) Wires-related 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 2020 Business Plan and Budget Proposal (Dated January 15, 2020) included as Appendix C to this application reflected TFO tariffs applied for or approved by the Commission at the time the AESO budget was prepared with some small adjustments related to revised payment estimates for Alberta PowerLine L.P. and with a recent Commission decision regarding one TFO's 2020 revenue requirement, as discussed in more detail below.

(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.

23 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.

24 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.

25 As part of the AESO Budget Review Process for its 2020 budget, AESO management consulted with stakeholders in a planning process that had been first established with stakeholders in 2005. AESO management proposed the *2020 Business Plan and Budget Proposal* to the AESO Board on January 15, 2020. This document (included as Appendix C to this application) 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 2020. The *2020 Business Plan and Budget Proposal* was also provided to stakeholders and posted on the AESO website.

26 The AESO's 2020 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; however, Board approval is expected in February 2020. The Budget Review Process moved through the first round of consultation with preliminary 2020 forecasts costs provided to stakeholders on November 29, 2019. The AESO will file a letter to advise the Commission of AESO Board approval once it has been received.

27 Additional information on the AESO's business priorities and budget for 2020 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 ▶ 2020.

4.2.2 Wires Costs

28 The 2020 forecast costs for wires are $1,916.7 million and represent approximately 80.0% of the AESO's transmission revenue requirement. Wires costs include primarily wires-related costs of TFOs as well as two small non-wires costs.

29 The AESO has determined the 2020 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,[32] approved in Decision 2010-606, referred to in Decision 2014-242[33] and updated in Decision 22093-D02-2017:[34]

(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

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[32] Exhibit 0026.00.AESO-2718, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, dated July 19, 2013, at paras. 53-57.
[33] Decision 2014-242, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, issued August 21, 2014, at para. 43.
[34] Decision 22093-D02-2017 at para. 37.

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.*

30 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."[35]

31 As noted above, the majority of the TFO tariffs have been filed and a number have been approved by the Commission or filed as a negotiated settlement. As a result, the 72% of an applied-for increase methodology reduced the TFO wires-related costs by only $15.4 million (or 0.01%) from wires-costs amounts filed.

32 The TFO tariff costs included in this application are included as Table D-2 of Appendix D to this application.

4.2.3 Ancillary Services Costs

33 The forecast 2020 costs for ancillary services are $257.8 million and represent approximately 11% 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.

34 Ancillary service costs are primarily a function of volume forecasts and market-based commodity pricing forecasts. The 2020 forecast costs for ancillary services were based on a forecast average pool price of $57.81/MWh.

4.2.4 Losses Costs

35 The 2020 forecast costs for transmission line losses are $113.5 million and represent approximately 5% of the AESO's transmission revenue requirement as provided in Table 4.2-1 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.

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

36 Losses costs are a function of volume forecasts and market-based commodity pricing forecasts. The 2020 forecast costs for losses were based on a forecast average pool price of $57.81/MWh.

4.2.5 Administrative Costs

37 The 2020 transmission-function forecast cost for administration is $99.0 million and represents approximately 4% of the AESO's transmission revenue requirement.

38 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;*

39 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 *2020 Business Plan and Budget Proposal* (Dated January 15, 2020) provided as Appendix C to this application[36] 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 4.2-1 above.

4.3 2020 Rates Update

40 For this Update Application, the AESO has applied the methodology approved in Decision 3473--D01-2015 and used the 2018 rate calculations included as Appendix B of the AESO 2018 ISO tariff filing[37] as the template for the 2020 rate calculations. The 2020 rate calculations are included as Appendix D to this application, in Tables D-1 through D-16.

41 The rate calculations use the following inputs:

(a) the 2020 forecast revenue requirement discussed in section 4 of this application;

(b) the functionalization and classification of wires costs approved for 2020 in Decision 22942-D02-2019;[38] and

(c) the 2020 forecast billing determinants prepared by the AESO.

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[36] Appendix A, AESO 2019 Business Plan and Budget Proposal (Dated October 31, 2018), page 7.
[37] Exhibit 0004.00.AESO-3473, Alberta Electric System Operator 2014 ISO Tariff Compliance Filing Pursuant to Decision 2014-242, revised as discussed in Exhibit 0044.01.AESO-3473, response to information request UCA-AESO-002.
[38] Exhibit 0265.02.AESO-2718, Alberta Transmission System Cost Causation Study Update dated January 17, 2014, page 7, Figure 6.

4.3.1 Specific Rate Changes

42 Where applicable, rates in the ISO tariff have been updated to reflect the 2020 forecast revenue requirement, 2020 wires costs functionalization and classification, and 2020 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*.

43 The levels for each of the above rates have been calculated in accordance with Appendix D to this application. The updated rate sheets themselves are provided in the Refiled ISO tariff. A blackline of the updated tariff rates and the applied-for 2018 ISO Tariff is provided as Appendix B to this application, and a blackline of the updated tariff rates and the currently effective 2019 ISO tariff[39] is provided as Appendix B.1 to this application.

4.3.2 Rate PSC, Primary Service Credit

44 The 2020 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.

45 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 4.3-1 below. The primary service credit amounts determined in Table 4.3-1 are reflected in Rate PSC of the Refiled ISO Tariff.

Table 4.3-1 – Calculation of 2020 Primary Service Credit

Rate Component	Rate DTS Charge	PSC Factor	Rate PSC Credit
Substation fraction	$14,291.00/month	79%	$11,290.00/month
First (7.5 × substation fraction) MW of billing capacity	$4,703.00/MW	79%	$3,715.00/MW
Next (9.5 × substation fraction) MW of billing capacity	$2,789.00/MW	79%	$2,203.00/MW
Next (23 × substation fraction) MW of billing capacity	$1,867.00/MW	79%	$1,475.00/MW
All remaining MW of billing capacity	$1,150.00/MW	100%	$1,150.00/MW

[39] Approved in Decision 24036-D01-2018.

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

46 The AESO most recently provided the derivation of the regulated generating unit connection costs ("RGUCC") charge in an attachment to the AESO's response to information request AUC-AESO-009 in its 2014 ISO tariff application proceeding.[40] That attachment included a calculation of the RGUCC charge for each calendar year 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.

47 The RGUCC charge calculation was reviewed in Decision 2007-106 in connection with the AESO's 2007 general tariff application, where the Alberta Energy and Utilities Board stated that "The Board has reviewed this calculation and considers the AESO RGUCC appears to be reasonable."[41] A value of $15.06/MW was included for the 2020 RGUCC in the attachment to the response to information request AUC-AESO-009 in the AESO's 2014 ISO tariff application proceeding.

48 The regulated generating unit connection cost charge has accordingly been updated to $15.00/MW in Rate STS in the Refiled ISO Tariff, being the 2020 value rounded to the nearest dollar.

4.3.4 Rider J, Wind Forecasting Service Cost Recovery Rider

49 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.[42] Since first being implemented in 2011, Rider J is expected to recover in 2020 all costs of the contracted wind forecasting service incurred to date.

50 On a cumulative forecast basis, the AESO will over collect $8,408 by the end of 2019. The wind forecasting service annual cost forecast for 2020 is $54,600. Annual wind powered generation metered energy forecast for 2020 is 4.6 million MWh, an increase of about 0.6 million MWh from 2019. The AESO proposes to set the Rider J charge at $0.00/MWh.

51 The decrease from $0.08/MWh in the currently approved 2019 ISO tariff to $0.00/MWh results from the decrease in the forecasting service annual cost along with the increase in expected 2020 forecast wind power generation metered energy, along with revenues collected under the 2019 ISO tariff rates for the first quarter of 2020. Table 4.3-2 below illustrates the changes from year to year to achieve as close to a zero balance as possible at the end of 2020.

[40] Exhibit 0109.03.AESO-2718, Attachment AUC-AESO-009.
[41] Decision 2007-106, *Alberta Electric System Operator 2007 General Tariff Application* (December 21, 2007), page 76.
[42] Exhibit 0026.00.AESO-2718, at paras. 124-126.

Table 4.3-2 – Wind Forecasting Service Cumulative Balance

Line No.	Description	Actual 2010 – 2017	Actual 2018	Forecast 2019	Forecast 2020
1	Contracted wind forecasting service ($000)	$2,533.8	$304.6	$304.6	$54.6
2	Volumes (GWh)	24,561.1	4,002.2	3,984.7	4,625.3
3	Rider J Charge ($/MWh)	-	0.09	0.08	0.00
4	Revenue ($000)	$2,487.3	$360.2	$318.8	$91.5
5	Annual (undercollection) / overcollection ($000)	($46.4)	$55.6	$4.7	$32.3
6	**Cumulative Balance (undercollection) / overcollection ($000)**	**($46.4)**	**$9.2**	**$23.4**	**$60.4**

52 The Rider J charge will decrease accordingly to $0.00/MWh in the Refiled ISO Tariff. The AESO will continue to monitor and report this amount in future tariff applications and updates.

4.3.5 2020 Forecast Billing Determinants

53 The rate calculations for the 2020 rates update are based on the AESO's forecast of billing determinants for 2020. The AESO prepares a long-term load forecast in accordance with the Act and the *Transmission Regulation*. The load forecast most recently prepared by the AESO is set out in the *AESO 2019 Long-term Outlook*, which contains a 2020 load forecast.

54 The *AESO 2019 Long-term Outlook* includes a 20-year peak load and electricity consumption forecast for Alberta. The load forecast is generated from historic trends with economic growth (gross domestic product, population and employment) information, oilsands production forecasts used as direct inputs into the forecast. The 2019 Long-term Outlook includes regional, area and substation level forecasts that consider location and site specific information. 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.

55 Billing determinants are calculated using historical and year-to-date ratios between DTS Energy and each individual billing determinant listed below in Table 4.3-2. The billing determinants used in the 2020 rate calculations are also provided in Table D-12 of Appendix D to this application.

56 Additionally, Table 4.3-2 below provides a comparison of the forecast billing determinants in this tariff update to actual 2019 billing determinants. Coincident demand billing determinants for the 2020 forecast have decreased by 2.4% compared to the 2019 forecast billing determinants Metered energy increased by 2.5% and billing capacity (which incorporates non-coincident metered demand, demand ratchets, and contract minimums) has increased by 0.8%, with a 1.1% increase in the first demand tier, an increase of 1.2% in the second demand tier, an increase of 1.1% in the third demand tier and an decrease of 0.2% in the last demand tier.

Table 4.3-3 – 2020 Forecast and 2019 Actual Billing Determinants

Rate DTS Billing Determinant	Units	2020 Forecast	2019 Actual	Increase (Decrease)	
				Amount	%
Coincident Metered Demand	MW-months	91,210.9	93,436.3	(2,225.5)	(2.4%)
Billing Capacity					
• Total Billing Capacity	MW-months	160,561.5	159,312.7	1,248.8	0.8%
• First (7.5×SF) MW	MW-months	37,281.1	36,875.0	406.1	1.1%
• Next (9.5×SF) MW	MW-months	35,072.1	34,656.1	416.1	1.2%
• Next (23×SF) MW	MW-months	43,920.9	43,425.9	495.0	1.1%
• All Remaining MW	MW-months	44,287.4	44,355.7	(68.3)	(0.2%)
Highest Metered Demand	MW-months	120,191.4	120,522.7	(331.3)	(0.3%)
Metered Energy (All Hours)	GWh	61,157.4	59,652.3	1,505.2	2.5%
DTS Market Participants	customer-months	5,477.6	5,407.4	70.2	1.3%
Pool Price	$/MWh	57.81	54.88	2.93	5.3%
Average Increase/(Decrease) Weighted by Revenue					**(4.2%)**

57 To further examine the reasonableness of the 2020 forecast billing determinants, Table 4.3-3 below provides a comparison of the forecast billing determinants in this ISO tariff update application to the 2016, 2017, 2018 and 2019 recorded billing determinants. The AESO considers that the increase in billing determinants forecast for 2020 is reasonable when compared to recorded billing determinants for prior years.

58 For 2020, the forecast decrease of 2.4% for Coincident Demand billing determinants reflects the expected continued decline of Coincident Demand billing determinants from 2018 to 2019 as shown in Table 4.3-3 below. A preliminary analysis of decline in Coincident Metered Demand billing determinants for 2019 indicates that the decline is likely a combination of additional behind-the-fence generation and increased transmission price responsive load. The bill impact of the forecast continuing decline of the billing determinant is reflected in the overall bill impact and discussed in Section 4.3.3 below.

59 Additionally, the Highest Metered Demand billing determinant is forecast to decrease by 0.3% 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.

Table 4.3-4 – 2019 Forecast and 2018, 2017 and 2016 Recorded Billing Determinants

Rate DTS Billing Determinants	Units	2020 Forecast	2019 Recorded	2018 Recorded	2017 Recorded	2016 Recorded
Coincident Demand	MW-months	91,210.9	93,436.3	95,806.9	94,486.6	92,111.9
Billing Capacity (Total)	MW-months	160,561.5	159,312.7	157,737.2	155,274.4	151,464.1
Highest Metered Demand	MW-months	120,191.4	120,522.7	121,845.0	120,536.9	115,502.5
Metered Energy (All Hours)	GWh	61,157.4	59,652.3	61,016.8	60,010.0	58,503.6
Market Participants (Total)	customer-months	5,477.6	5,407.4	5,285.1	5,283.2	5,255.7

60 Overall, the AESO considers that the 2020 forecast provides the best estimate, given the information available, of billing determinants for the rate calculations in this application.

4.3.6 Bill Impacts

61 As noted in section 4.2 of this application, the AESO's 2020 forecast revenue requirement represents an increase of $15.0 million (or 0.6%) from the total forecast costs for 2019.

62 At the same time, billing determinants have also changed from the 2019 forecast on which currently-approved rates are based. As a result, the AESO's 2020 updated rates represents an overall increase of 5.7% from the 2019 rates currently in place, including an increase of 6.5% to Rate DTS, *Demand Transmission Service*, and a decrease of 9.0% to Rate STS, *Supply Transmission Service*.

63 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.

64 The increases and decreases to the different components of Rate DTS are provided in Table 4.3-4 below. The Rate DTS increase of 6.5% represents a revenue-weighted average decrease over all components of Rate DTS.

65 The smaller increase in the bulk system – coincident demand charge, and the larger increases in the point of delivery charges, result from the changes in functionalization and classification ratios approved in the updated transmission cost causation study approved in the Decision.[43] As discussed above in Section 4.2.2, the impact of the decline in coincident demand billing determinants results in an increase of the coincident demand Charge over 2019 rates. To approximate this impact, the 2018 over 2017 growth rate (or 1.4%) was applied to 2019 coincident demand billing determinants to do a forecast of higher 2020 coincident demand billing determinants. This analysis indicates that the coincident demand Charge would have been approximately $10,153/MW rather than $10,814/MW or a reduction of 3.5% from 2019 rates if coincident demand billing determinants were to continue to grow in 2020 at a 2018 growth rate.

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[43] Decision, para. 74.

66 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.

67 To allow individual market participants to estimate the impact of the 2020 rates on their own Rate DTS bills, the AESO has included a bill impact estimator as Table D-13 in the rate calculations included as Appendix D to this application. The bill impact estimator calculates bills for a given set of billing inputs under both the current 2019 Rate DTS and the updated 2020 Rate DTS, to allow the impact of the rates update on an individual service to be estimated.

Table 4.3-5 – Increase (Decrease) for 2020 Rate DTS Components

Rate DTS Charge	Unit	Proposed (1 Apr 2020)	Current (1 Jan 2019)	Increase (Decrease)
Bulk System				
• Coincident Demand	$/MW	$10,814.00	$10,524.00	2.8%
• Energy	$/MWh	$1.13	$1.26	(10.3%)
Local System				
• Billing Capacity	$/MW billing	$2,799.00	$2,359.00	18.7%
• Energy	$/MWh	$0.86	$0.87	(1.1%)
Point of Delivery				
• Participant × SF	$/month	$14,291.00	$9,062.00	57.7%
• First (7.5 × SF) MW BC	$/MW	$4,703.00	$3,669.00	28.2%
• Next (9.5 × SF) MW BC	$/MW	$2,789.00	$2,298.00	21.4%
• Next (23 × SF) MW BC	$/MW	$1,867.00	$1,603.00	16.5%
• Remaining MW BC	$/MW	$1,150.00	$1,038.00	10.8%
Operating Reserve	% of Pool Price	7.13%	8.50%	(16.1%)
Transmission Constraint Rebalancing Charge	$/MWh	$0.002	$0.002	0.0%
Voltage Control	$/MWh	$0.05	$0.05	0.0%
Other System Support	$/MW	$24.00	$36.00	(33.3%)
Net Change (revenue weighted)				**6.5%**

68 In recent ISO tariff applications, the AESO provided analyses of the impacts on market participants' bills of the Rate DTS changes proposed in the applications. A similar analysis has been completed for this Update Application, and is provided as Appendix F.

69 With respect to bill impacts arising from the 2006 ISO tariff application, the EUB in Decision 2005-096 found that rate shock should be given secondary consideration as a rate design criterion, and that on balance, if rates reflect cost causation, barring unusual regulatory events such as regulatory lag or a dramatic change in cost structure, there should be little need to be concerned about the principles of rate shock and gradualism. With respect to bill impacts arising from the 2007 ISO tariff application, Decision 2007-106 directed that they be assessed against the then currently-approved rates and include all components of a bill including commodity costs.

70 For this Update Application, the AESO has accordingly compared, on a per-point-of-delivery basis, bills under the proposed 2020 Rate DTS to bills under the 2019 Rate DTS. The AESO

considers that such a comparison most clearly illustrates the impact of changes to transmission cost functionalization and classification discussed in this section of the application.

71 The bill impact analysis was based on an extract of actual market participant billing determinants for each Rate DTS point of delivery from January 2017 to December 2019, including coincident metered demand, substation fraction, and actual pool price for metered energy at the point of delivery.

72 For the comparison, the proposed 2020 Rate DTS and the 2019 Rate DTS were applied to the same billing determinants, including pool price, at each point of delivery. This approach isolates the increases attributable to Rate DTS changes only.

73 Table 4.3-6 provides the distribution of total bill increases over the 558 points of delivery included in the analysis. The AESO notes that operating reserve charges and the transmission constraint rebalancing charge under the proposed 2020 Rate DTS represent an estimate only, as actual charges will reflect the hourly allocation as currently approved and proposed to be continued in Rate DTS. Details for the bill impact analysis are provided as Appendix F to this application.

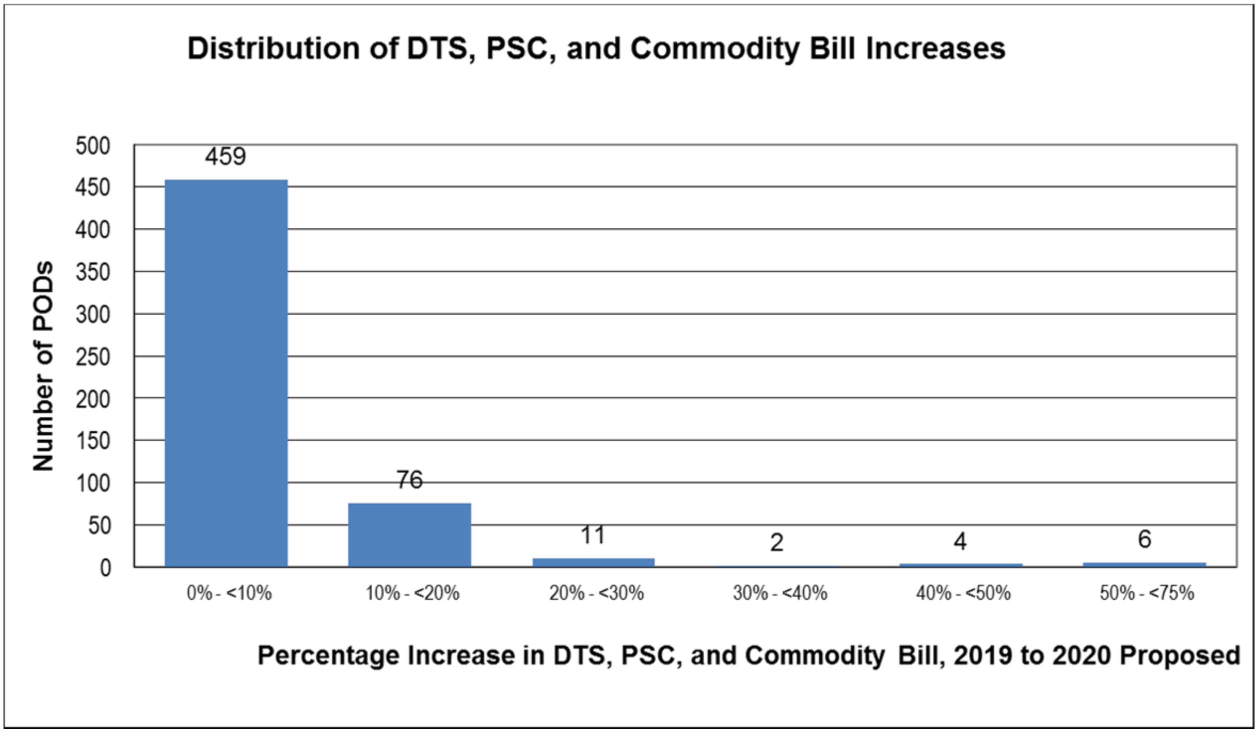
Table 4.3-6 – Summary of average per-POD bill impacts

Description	***Billing Capacity***				***Total***
All Load Factors	***0 to <7.5***	***7.5 to <17***	***17 to <40***	***40 to 183***	
Number of Accounts	149	150	159	100	558
Monthly Usage (MWh)	925	4,607	9,977	25,425	8,885
Average Billing Capacity (MW)	3.1	12.2	26.1	68.0	23.7
Load Factor (%)	33%	52%	52%	55%	47%
2019 Monthly Bill ($)	$94,439	$428,292	$917,893	$2,272,595	$809,175
2020 Monthly Bill ($)	$101,548	$447,820	$950,440	$2,332,086	$836,258
2019-2020 Increase ($)	$7,109	$19,527	$32,547	$59,491	$27,083
2019-2020 Increase (%)	13.2%	5.7%	4.7%	3.7%	7.1%

74 As illustrated in Figure 4.3-1 below, the majority of Rate DTS points of delivery (459 points of delivery, or about 82%) receive increases of zero to 10% based on Rate DTS charges, Rate PSC credits and commodity costs. In addition:

- 76 points of delivery (about 14% of the total) received increases from +10% to +20%, and
- 11 points of delivery (about 2% of the total) receive increases from +20% to +30%.

Figure 4.3-1 – Distribution of DTS, PSC and Commodity Bill Increases



75 Decision 2007-106 directed that services receiving an increase greater than 10% be examined in more detail. Table F-6 in Appendix F accordingly provides additional information on the 91 services receiving increases greater than 10% due to the proposed 2020 Rate DTS. Of those services, 24 (about 35%) are dual-use sites where services are provided under both Rate DTS and Rate STS. In Decision 2008-037 regarding the 2007 General Tariff Application Refiling, the Commission commented, with respect to dual-use services receiving greater than 10% increases at that time, "The Commission does not consider it reasonable to offer a subsidy to these dual-use customers as there is no evidence to suggest that their total DTS and STS billings exceed the threshold."[44]

76 The AESO further notes that all 99 services receiving greater than 10% increases have very low billing capacity or very low load factors. Load factors for the 99 sites average only 12.8%. Disregarding dual-use sites, only 33 of 71 load only sites have a load factor of over 10%. Out of these 33 sites, four are isolated sites serving remote communities with billing capacity ranging from 0.03 MW to 0.14 MW totaling 0.3 MW and another 13 are small services with billing capacity of less than 2 MW each. The remaining 16 services have billing capacity ranging from 2.1 MW to 19.8 MW with an average of 6.2 MW and load factor ranging from 14% to 42% with an average of 23%. These 16 services receive bill increases of 10.4% to 16.7% with an average of 12.6%. The monthly bill for these 16 services increases by $5,888 to $26,811 with an average of $13,581. These low billing capacities or low load factors result in the larger-than-average increases at these sites due to three effects:

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[44] Decision 2008-037, page 6.

(a) bills at sites with very low monthly usage minimize the effect of including commodity costs when assessing bill impacts and tend to reflect only transmission charge increases;

(b)bills at low-billing-capacity and low-load-factor sites predominately reflect fixed charges, and fixed charges have increased more than average in Rate DTS as illustrated in Table 4.3-5 above and more detail in Table D-13 in Appendix D of this application; and

(c) bills at low-load-factor sites predominately reflect charges based on billing capacity, and billing capacity demand charges have increased more than average in Rate DTS as illustrated in Table 4.3-5 above and more detail in Table D-13 in Appendix D of this application.

77 Given the comments in Decision 2005-096, 2007-106, and Decision 2008-037 regarding cost causation, bill impacts, and dual-use sites, the AESO does not propose any rate modifications or additional rates or riders to mitigate bill impacts arising from its proposed 2020 Rate DTS.

78 Finally, the AESO notes that the bill impact analysis presented in Appendix F is an estimate of the impact of the proposed 2020 Rate DTS. Bills for an individual Rate DTS point of delivery will vary from these estimated depending on actual demand and usage at the point of delivery, including variations in hourly pool price and the hourly allocation of operating reserve costs.

79 The changes to the different components of Rate STS are provided in Table 4.3-6 below. The Rate STS decrease of 9.0% represents a revenue-weighted average decrease over all components of the rate.

80 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 regulated generating unit ("RGU") connection costs charge.

Table 4.3-7 – Increase (Decrease) for 2020 Rate STS Components

Rate STS Charge	Unit	Proposed (1 Apr 2020)	Current (1 Jan 2019)	Increase (Decrease)
Losses	% of Pool Price	3.01%	3.26%	(7.7%)
RGU Connection Costs	$/MW	$15.00	$45.00	(66.7%)
Net Change (revenue weighted)				**(9.0%)**

81 In particular, the AESO notes that the loss factors provided in Table 4.3-6 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[45] in Proceeding 790, although the AESO notes that the losses charge remains as approved on an interim basis in Commission Decision 2014-242.[46]

[45] 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.
[46] Decision 2014-242, *Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update* (August 21, 2014), para. 730.

4.4 Maximum Investment Levels Update

82 The tariff update approach described in section 4.1.1 of this application includes updating investment amounts approved in the Decision[47] to revise the existing point-of-delivery cost curve to Option #2[48] and reflecting an escalation factor based on a composite of specified recent inflation indices from 2018 dollars to 2020 dollars.

83 The AESO has accordingly updated the composite inflation index used for developing the point of delivery cost function to 2019, using additional Statistics Canada cost index values and the most recent Conference Board of Canada forecast of the Alberta consumer price index. Table 4.4-1 below provides the composite inflation index values for 2018, as included in the 2018 ISO tariff filing, and for 2020 as updated in this application.

Table 4.4-1 – Escalation Factor for Composite Inflation Index

	Year	Basis	Present Value Factor
2018 Tariff Application	2018	Actual	1.6169
2019 (not applicable)	2019	Forecast	1.6521
2020 Tariff Update	2020	Forecast	1.6935
2020 Escalation Factor (over 2018)	1.6935_{2020} / 1.6169_{2018} =		1.0473

84 The resulting escalation factor for updating the 2020 maximum investment levels in section 4 of the ISO tariff is 1.0473, which represents an increase to the 2018 maximum investment levels as determined using Option 2[49] as directed by the Commission.[50] 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 E of this application.

85 The AESO has applied the resulting 1.0473 escalation factor to the 2018 Rate DTS maximum investment levels to determine the 2020 Rate DTS maximum investment levels, as summarized in Table 4.4-2 below. Table 4.4-2 also includes the calculation of the corresponding Rate PSC maximum investment levels for each year.

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[47] Decision, para 201.
[48] Exhibit 22942.0018.03, Appendix G – Options for POD Cost Function Workbook, Tab 'Option 2 Investment Proposed', Cells C11 to G11.
[49] Exhibit 0018.03, Revised Appendix V – Options for POD Cost Function Workbook, Tab 'Option 2 Investment Proposed', Cells C11 to G11.
[50] Decision, para. 201.

Table 4.4-2 – Calculation of 2020 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
2020 Escalation Factor (over 2018)	**1.0473**		
2020 Maximum Investment Levels			
Substation fraction (for new points of delivery only)	$105,150/year	21%	$22,080/year
First (7.5 × substation fraction) MW of contract capacity	$34,600/MW/year	21%	$7,270/MW/year
Next (9.5 × substation fraction) MW of contract capacity	$20,550/MW/year	21%	$4,320/MW/year
Next (23 × substation fraction) MW of contract capacity	$13,750/MW/year	21%	$2,890/MW/year
All remaining MW of contract capacity	$8,450/MW/year	0%	$0/MW/year

5 Conclusion

86 Based on all of the foregoing, the AESO submits that the Compliance Filing fully complies with all applicable refiling directions in the Decision and that the Update Application complies with the update methodology approved by the Commission for the AESO's tariff. The AESO respectfully submits that the rates and terms and conditions arising from this Compliance Filing and Update Application will be just and reasonable and the AESO requests that the Commission:

(a) confirm that the Commission's refiling directions in the Decision have been satisfactorily responded to; and

(b) approve the Refiled ISO Tariff (2020 ISO tariff) included as Appendix A of this Compliance Filing, including the updated amounts included in Appendix E, and (ii) the proposed 2020 ISO tariff Rate DTS, Rate FTS, Rate DOS, Rate XOS, Rate XOM, Rate PSC, Rate STS, Rider J and Section 4 included in Appendix A.

87 The AESO requests that the Refiled ISO Tariff be made effective no earlier than the first day of the month at least 30 days after the date of the Commission's decision regarding the Refiled ISO tariff to allow adequate time to implement the ISO tariff and to program and test the rates in the AESO's billing system.

88 The AESO further requests that the Update Application be approved on an interim refundable basis no later than March 1, 2020 and effective no later than April 1, 2020 in order to minimize amounts recovered or refunded through Rider C, *Deferral Account Adjustment Rider*, reduce deferral account balances, and potentially reduce amounts transferred between market participants in future deferral account reconciliations.

89 All of which is respectfully submitted this 31st day of January 2020.

Alberta Electric System Operator

Per: Miranda Keating Erickson
Vice-President, Markets