Alberta Electric System Operator
Amended 2018 ISO Tariff Application

Date: August 17, 2018

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1 Application

1 The Independent System Operator ("ISO"), operating as the Alberta Electric System Operator ("AESO"), originally filed an application with the Alberta Utilities Commission ("Commission") on September 14, 2017[1] for approval of the then-proposed 2018 ISO tariff.

2 This amended application (referred to herein as, "this application", "comprehensive 2018 ISO tariff application" or "2018 ISO tariff application") is made pursuant to sections 30 and 119 of the *Electric Utilities Act*, SA 2003, c E 5.1 ("Act"), under which the AESO is requesting approval from the Commission of its amended proposed 2018 ISO tariff (referred to herein as, "the amended 2018 ISO tariff", "the 2018 ISO tariff" or the "proposed 2018 ISO tariff"), which sets out the rates to be charged for, and the terms and conditions that apply to, each class of system access service provided by the AESO, pursuant to section 29 of the Act.

3 This comprehensive 2018 ISO tariff application provides the forecast revenue requirement for the costs to be recovered through the AESO's rates. This application also proposes changes to the rates and terms and conditions provided for in the current ISO tariff.

1.1 Background

4 The AESO is a statutory corporation established by subsection 7(1) of the Act. Subsection 14(3) of the Act requires that the AESO be managed so that, on an annual basis, no profit or loss results from its operation.

5 The AESO's forecast revenue requirement includes costs related to transmission wires, ancillary services, transmission line losses, and the AESO's own administration. These costs are approved on a forecast basis through various processes as outlined below in this application:

(a) Costs related to transmission wires reflect the rates paid by the AESO to owners of transmission facilities ("TFOs") in the TFO tariffs approved by the Commission under section 37 of the Act;

(b) Costs of ancillary services 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) Costs of transmission line losses reflect recovery of the prudent costs of transmission line losses under subsection 30(4) of the Act; and

(d) Costs of the AESO's own administration reflect the transmission-related costs and expenses incurred by the AESO, as described in subsection 1(1)(g) of the *Transmission Regulation*, AR 86/2007 ("*Transmission Regulation*").

6 The AESO is not seeking approval of its forecast revenue requirement. The ancillary services costs, losses costs, and administrative costs described above are approved by the AESO Board (consisting of the "ISO members" described in section 8 of the Act) in accordance with the *Transmission Regulation*. Section 3 of the *Transmission Regulation* requires the AESO to consult with market participants with respect to proposed costs to be approved by the AESO Board. Subsection 46(1) of the *Transmission Regulation* provides that these costs, once approved by the AESO Board, must be considered "prudent" by the Commission unless an interested person satisfies the Commission otherwise.

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[1] Exhibit 22942-X0002, revised on October 11, 2017, Exhibit 22942-X0002.01.

1.2 Organization of application

7 This application is organized into sections as follows.

8 **1 Introduction** — Section 1 provides background regarding this application and specifies the relief requested.

9 **2 Stakeholder consultation** — Section 2 provides an overview of stakeholder consultation concerning the proposed 2018 ISO tariff, prior to filing this application.

10 **3 Revenue requirement** — Although the AESO is not seeking approval in this application of its forecast revenue requirement, section 3 summarizes the AESO's revenue requirement forecast for 2018, including costs that are approved either by the Commission (for TFO tariffs) or by the AESO Board (for ancillary services, transmission line losses, and the AESO's own administrative costs). Section 3 also discusses the Budget Review Process ("BRP") used to review the revenue requirement with stakeholders.

11 **4 Transmission cost causation** — Section 4 summarizes changes to the functionalization and classification of transmission system costs determined through a transmission cost causation study and point of delivery cost function analysis.

12 **5 Rate design** — Section 5 discusses proposed changes to the AESO's rates including incorporation of the 2018 forecast revenue requirement and 2018 forecast billing determinants.

13 **6 Riders** — Section 6 discusses proposed changes to the deferral account reconciliation methodology and riders.

14 **7 Terms and conditions** — Proposed substantive changes to the AESO's terms and conditions are discussed in section 7.

15 **8 Other matters** — Section 8 discusses cost responsibility for compliance with the CIP Alberta reliability standards and the proposed tariff treatment for energy storage.

16 **9 Responses to directions** — Section 9 summarizes all outstanding Commission directions responded to in this application.

17 **10 Conclusion**.

18 **A-Y Appendices** — The appendices to this application provide studies, data, and additional information in support of the proposed 2018 ISO tariff. The following table identifies the appendices filed with the original application on September 14, 2017 that remain unchanged, as well as those that were subsequently revised or updated, and the revised appendices filed with this application on August 17, 2018, all of which form part of this application.

Appendix	Title of Appendix and Exhibit Number	Status
A	AESO Board Decision 2017-2018-BRP-001 Exhibit 22942-X0022	Unchanged from Exhibit 22942-X0022
B	AESO 2017-2018 Business Plan and Budget Proposal Exhibit 22942-X0023	Unchanged from Exhibit 22942-X0023

Appendix	Title of Appendix and Exhibit Number	Status
C	Stakeholder Consultation Materials Exhibit 22942-X0024	On October 23, 2017, the AESO filed Revised Appendix C as Exhibit 22942-X0024.01 Amended Appendix C – Updated Consultation Materials, attached, supersedes Exhibit 22942-X0024.01
D	Transmission System Cost Causation Study 2018 Update Exhibit 22942-X0025	Unchanged from Exhibit 22942-X0025
E	Transmission System Cost Causation 2018 Update Workbook Exhibit 22942-X0026	Unchanged from Exhibit 22942-X0026
F	Point of Delivery Cost Function Report Exhibit 22942-X0027	On October 11, 2017, the AESO filed Revised Appendix F as Exhibit 22942-X 0027.01 Amended Appendix F - Updated Point of Delivery Cost Function Report, attached, supersedes Exhibit 22942-X0027.01
G	Point of Delivery Cost Function Workbook Exhibit 22942-X0003	Amended Appendix G – Updated Point of Delivery Cost Function Workbook, attached, supersedes Exhibit 22942-X0003
H	2018 Rate Calculations Exhibit 22942-X0004	Unchanged from Exhibit 22942-X0004
I	2018 Bill Impact Analysis Exhibit 22942-X0005	On March 23, 2018, the AESO filed Exhibit 22942-X0005.02 to replace Exhibit 22942-X0005 with the correct spreadsheet. On January 18, 2018, the AESO had filed the wrong replacement spreadsheet as Exhibit 22942-X0005.01 Unchanged from Exhibit 22942-X0005.02
J	Transmission Rate Projection Workbook Exhibit 22942-X0006	On April 27, 2018, the AESO filed the 2018 Updated Transmission Rate Projection Workbook, as Exhibit 22942-X0126 Unchanged from Exhibit 22942-X0126

Appendix	Title of Appendix and Exhibit Number	Status
K	2018 Contribution Policy Investment Levels Workbook Exhibit 22942-X0007	On October 11, 2017, the AESO filed Revised Appendix K as Exhibit 22942-X0007.01 Unchanged from Exhibit 22942-X0007.01
L	Examination of Rider C and Deferral Account Reconciliation Methodology Report Exhibit 22942-X0008	Unchanged from Exhibit 22942-X0008
M	Commission Closure Letter Exhibit 22942-X0009	Unchanged from Exhibit 22942-X0009
N	AESO 2017 Long-term Outlook Exhibit 22942-X0010	Unchanged from Exhibit 22942-X0010
O	Modeling Dispatch Operations of Energy Storage Facilities in the Alberta Wholesale Electricity Market Exhibit 22942-X0011	Unchanged from Exhibit 22942-X0011
P	Comparison between Electricity Storage and Existing Alberta Site Dispatch Profiles Exhibit 22942-X0012	Unchanged from Exhibit 22942-X0012
Q	Energy Storage Integration Recommendation Paper and Stakeholder Comments Exhibit 22942-X0013	Unchanged from Exhibit 22942-X0013
R	Proposed 2018 ISO Tariff Exhibit 22942-X0014	On October 11, 2017, the AESO filed Revised Appendix R as Exhibit 22942-X 0014.01 Amended Appendix R –Amended Proposed 2018 ISO Tariff, attached, supersedes Exhibit 22942-X0014.01
S	Blackline Comparison of Proposed and Current Rates, Riders and Appendices Exhibit 22942-X0015	Amended Appendix S – Updated Blackline Comparison of Proposed and Current Rates, Riders and Appendices, attached, supersedes Exhibit 22942-X0015
S^1	Blackline of Changes to Proposed Rates, Riders and Appendices filed on September 14, 2017	New

Appendix	Title of Appendix and Exhibit Number	Status
T	Comparison Table of Proposed and Current Terms and Conditions Exhibit 22942-X0016	On October 11, 2017, the AESO filed Revised Appendix T as Exhibit 22942-X 0016.01 Amended Appendix T – Updated Comparison Table of Proposed and Current Terms and Conditions, attached, supersedes Exhibit 22942-X0016.01
U	Defined Terms Used in the ISO Tariff Exhibit 22942-X0017	Amended Appendix U – Updated Defined Terms Used in the ISO Tariff, attached, supersedes Exhibit 22942-X0017
V	Options for POD Cost Function Workbook Exhibit 22942-X0018	On October 11, 2017, the AESO filed Revised Appendix V as Exhibit 22942-X 0018.01 Amended Appendix V – Updated Options for POD Cost Function Workbook, attached, supersedes Exhibit 22942-X0018.01
W	Option 2 Point of Delivery Cost Function Workbook Exhibit 22942-X0019	Unchanged
X	Option 4 Point of Delivery Cost Function Workbook Exhibit 22942-X0020	Amended Appendix X – Updated Option 4 Point of Delivery Cost Function Workbook, attached, supersedes Exhibit 22942-X0020
Y	Blackline Comparison of Proposed and Current Defined Terms Used in the ISO Tariff Exhibit 22942-X0021	Revised Appendix Y - Updated Blackline Comparison of Proposed and Current Defined Terms Used in the ISO Tariff, attached, supersedes Exhibit 22942-X0021

1.3 Relief requested

19 Based on the entirety of the information provided with this application, the AESO requests approval of this application, including:

(a) approval of the bulk system, regional system, and point of delivery cost functionalization, the bulk system and regional system cost classification, and point of delivery cost function for 2018, 2019, and 2020 as presented in section 4 of this application;

(b) approval of the proposed 2018 ISO tariff in Appendix R to this application, including rates (except the monetary amounts), riders, terms and conditions, and appendices;

(c) confirmation from the Commission that the AESO's entire forecast revenue requirement is subject to deferral account treatment;

(d) confirmation from the Commission that the AESO has adequately responded to the Commission's outstanding directions; and

(e) such other relief as the Commission deems appropriate.

20 In the event that the Commission does not direct changes to the proposed rates and rider structures, the AESO requests that the 2018 ISO tariff be effective no earlier than the first day of the month at least 30 days after the date of the Commission's decision regarding the proposed ISO tariff to allow adequate time to implement the ISO tariff and to program and test the rates in the AESO's billing system. In the event that the Commission directs changes to the proposed rates and rider structures, then the AESO requests that the 2018 ISO tariff be effective no earlier than the first day of the month at least 60 days after the date of the Commission's decision regarding the AESO's compliance filing, to allow adequate time to implement the ISO tariff and to program and test the rates in the AESO's billing system.

21 The AESO plans to file a 2019 ISO tariff update application as soon as practical after the filing of this amended application in order to ensure that the monetary amounts in the rates can be updated and in effect on January 1, 2019. The 2019 ISO tariff update application will consist of formulaic updates to: (i) the AESO's 2019 annual revenue requirement, based on the AESO's updated forecast costs for 2019; (ii) rate, rider, and maximum investment level amounts using the rate calculation methodology already approved by the Commission in Decision 3473-D01-2015, and (iii) the investment amounts first approved in Decision 3473-D01-2015, then updated in Decision 21302-D01-2016, Decision 22093-D01-2016 and Decision 23065-D01-2017, in accordance with an escalation factor. In the AESO's view, the updates that will be proposed in the 2019 ISO tariff update application will limit potential misallocations that might occur if the AESO were to continue to rely on Rider C, *Deferral Account Adjustment Rider*, to allocate revenue and cost imbalances to market participants during the proceeding for this 2018 ISO tariff application.

2 Consultation

22 Information and conclusions from the AESO's various consultation initiatives and processes assisted the AESO in developing the proposals included in this application. Where appropriate, the AESO refers to stakeholder consultation in the relevant sections of this application, but does not repeat all comments and exchanges that took place throughout the consultation. Documentation of the consultation processes can be found in Appendix C of this application.

23 Stakeholder consultation for the originally filed 2018 ISO tariff was conducted from August 2015 through June 2017 and included a number of components:

(a) an initial stakeholder session to consult on the proposed scope of the 2017 ISO tariff application (as it was initially contemplated);

(b) a stakeholder session on the AESO's work to address Commission directions regarding Rider C, *Deferral Account Adjustment Rider*, deferral account reconciliations, and ISO tariff updates;

(c) five general stakeholder sessions to consult on the development of the originally filed 2018 ISO tariff application, including detailed analysis of the AESO's proposed tariff treatment of energy storage, transmission cost causation study, point-of-delivery cost function, and changes to the terms and conditions; and

(d) a final stakeholder session to provide stakeholders with a preview of the AESO's proposed changes to the current ISO tariff terms and conditions, and draft rates and investment levels.

24 The AESO conducted additional stakeholder sessions in March and April 2018 to gather input regarding the 12 coincident peak ("12 CP") methodology and the distribution facility owner ("DFO") customer contribution ("DFO CC") policy, as contemplated by the Commission in its January 19, 2018 letter,[2] which suspended Proceeding 22942 while the AESO could consult on the two issues.

25 The AESO updated the Commission and stakeholders on April 30, 2018[3] to summarize the conclusions arising from the additional stakeholder sessions regarding the 12 CP methodology and DFO CC issues. The AESO proposed that the bulk (12 CP) and regional tariff design should be thoroughly analyzed in a consultation process outside of Proceeding 22942 and therefore the AESO requested the Commission to direct that the issue of whether the applied-for bulk/regional tariff design should be changed will not be considered in Proceeding 22942. The AESO also advised the Commission and stakeholders that it would not propose changes to the DFO CC policy in the proposed 2018 ISO tariff.

26 In its June 29, 2018 ruling,[4] regarding the AESO's proposal to conduct a consultation process regarding the bulk and regional tariff design, the Commission:

(a) agreed with the AESO's proposal to complete a thorough analysis of the 12 CP methodology outside of Proceeding 22942;

(b) found that energy storage tariff policies can be considered in Proceeding 22942; and

[2] Exhibit 22942-X0112.
[3] Exhibit 22942-X0129 and Exhibit 22942-X0128.
[4] Exhibit 22942X0156.

(c) indicated that an examination of the DFO CC policy remains within scope for Proceeding 22942.

27 Other matters raised during the consultation process prior to the original application being filed that are not addressed in this application include:

(a) the potential for a firm export rate; and

(b) review of the construction contribution policy and its relation to the AESO's determination of whether transmission facilities are in excess of good electric industry practice.

28 The AESO notes that rates in the 2018 ISO Tariff Update[5] will remain in effect until the Commission-approved rates for this application become effective. The rates applied for in this application are based on the same tariff design as in the 2018 ISO Tariff Update, with the only significant difference being the use of more current information, including an updated transmission cost causation study, costs forecast and billing determinants forecast. The AESO considers the rates applied for in this application to be an improvement over the rates in 2018 ISO Tariff Update.

[5] Exhibit 23065-X0002, Appendix C - 2018 Rates Calculations.

3 AESO 2018 revenue requirement

29 As noted above, the AESO's forecast revenue requirement consists of costs related to wires, ancillary services, transmission line losses and the AESO's own administrative costs (which comprise general and administrative costs, other industry costs and capital costs of the AESO). The AESO's forecast costs for 2018 are detailed in column A of Table 3-1. For comparison, Table 3-1 includes costs approved in the AESO Board Decision for 2018 (included as Appendix A to this application), forecast costs for 2018,[6] updated forecast costs for 2017 and the recorded costs for 2016, in columns A, D and G, respectively.

Table 3-1 – 2018 forecast, 2017 updated forecast and 2016 recorded cost components

Cost Component	2018	Increase (Decrease)		2017	Increase (Decrease)		2016
	Forecast ($ 000 000)	($ 000 000)	%	Updated Forecast ($ 000 000)	($ 000 000)	%	Recorded Costs ($ 000 000)
	A	B	C	D	E	F	G
Wires	$1,719.5	($14.5)	(0.8%)	$1,734.0	$22.6	1.3%	$1,711.4
Ancillary services	179.2	60.4	50.8%	118.9	25.7	27.5%	93.2
Losses	96.8	22.7	30.7%	74.1	33.0	80.4%	41.1
Administrative	100.8	2.2	2.2%	98.7	(1.7)	(1.7%)	100.4
Revenue Requirement	**$2,096.4**	**$70.8**	**3.5%**	**$2,025.6**	**$79.5**	**4.1%**	**$1,946.1**

Note: Numbers may not add due to rounding

30 The 2018 forecast costs represent an increase of $70.8 million (or 3.5%) over the 2017 updated forecast costs. The increase primarily results from a forecast increase of $60.4 million (or 50.8%) in ancillary services reflecting increased costs from active operating reserve costs primarily driven by the higher pool price of $43 (compared to forecast $24 for 2017), further discussed in section 4 of Appendix B to this application, *AESO 2017-2018 Business Plan and Budget Proposal*.

3.1 AESO Board approval of costs

31 The AESO is not seeking approval in this application of its 2018 forecast revenue requirement. The AESO's forecast costs are approved through other processes provided for in relevant legislation. These costs, as set out in column A of Table 3-1, were addressed in the *AESO 2017--2018 Business Plan and Budget Proposal*, dated June 2017, included as Appendix B of this application and the *AESO Board Decision 2017-2018*, dated August 2017, included as Appendix A to this application.

32 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 pursuant to section 37 of the Act. The wires costs forecast included in the *AESO 2017 and 2018 Business Plan and Budget Proposal* reflected TFO tariffs applied for or approved by the Commission at the time the AESO budget was prepared in early 2017, as discussed in more detail below.

[6] 2017 forecast costs and updated wires costs reflecting recent TFO filings, compliance filings and decisions for 2017.

(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 as provided for in subsection 30(4) of the Act.

(c) Losses costs reflect recovery of the prudent costs of transmission line losses as provided for in subsection 30(4) of the Act.

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

33 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*. As noted above, section 3 of the *Transmission Regulation* requires that the AESO consult with market participants concerning proposed costs to be approved by the AESO Board. Subsection 48(1) of the *Transmission Regulation* provides that a reference in the Act to "prudent" or "appropriate" 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 "prudent" by the Commission unless an interested person satisfies the Commission otherwise.

34 The practice established by the AESO to conduct consultation on ancillary services, losses and administrative costs is the Budget Review Process ("BRP"). The BRP is an open and transparent process which facilitates a business initiative and cost review with stakeholders. At the conclusion of the BRP, 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.

35 As part of the BRP for the AESO's 2017 and 2018 budgets, AESO management consulted with stakeholders in a planning process that had been first established with stakeholders in 2009. In March 2017, the AESO reviewed the business initiatives established for 2017 and 2018 and prepared a forecast budget required to deliver those business initiatives. Following the consultation and the incorporation of appropriate amendments arising from it, AESO management submitted the *AESO 2017-2018 Business Plan and Budget Proposal* to the AESO Board on June 6, 2017. This document (included as Appendix B to this application) includes details regarding 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 2018. The *AESO 2017-2018 Business Plan and Budget Proposal* was also provided to stakeholders and posted on the AESO website.

36 The AESO's 2018 forecast costs were approved by the AESO Board on August 2, 2017. The Board Decision was posted on the AESO website on August 8, 2017 and is included as Appendix A to this application.

37 Additional information on the AESO's business priorities and budget for 2018 is available on the AESO website at www.aeso.ca by following the path: AESO ▶ About the AESO ▶ Planning and financial reporting ▶ 2017-2018.

3.2 Wires costs

38 The 2018 forecast costs for wires are $1,719.5 million and represent approximately 82% of the AESO's revenue requirement. Wires costs primarily include wires-related costs of TFOs as well as two small non-wires costs.

39 The AESO determines wires costs for TFOs using the approach described in section 2.2 of the AESO's 2017 ISO Tariff Update Application and approved in Decision 22093-D02-2017. Specifically, the AESO includes costs that reflect the status of each TFO's application for the effective tariff year of the AESO's revenue requirement.

> *(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.*

40 The specific determinations of the forecast wires cost for each TFO, as totaled in Table 3-1 above, column A, are as follows.

(a) **AltaLink** — AltaLink received final approval of 2018 TFO tariff costs of $892.1 million. The AESO has accordingly included $892.1 million as the forecast TFO tariff costs for AltaLink for 2018.

(b) **ATCO Electric** — ATCO Electric filed for approval of 2018 TFO tariff costs of $606.6 million. ATCO Electric filed for approval in a second compliance filing of 2017 TFO tariff costs of $673.8 million. As well, ATCO Electric filed for approval of a 2013-2014 deferral account reconciliation shortfall of $0.2 million allocated to 2017. The AESO has accordingly included $625.4 million as the forecast TFO tariff costs for ATCO Electric for 2018.

ATCO Electric's TFO tariff costs are offset by payments to the AESO in respect of pool price for electric energy provided to isolated communities in accordance with the *Isolated Generating Units and Customer Choice Regulation*. The isolated generation cost offset is estimated at $3.1 million for 2018, based on 2016 recorded volumes for isolated communities and the 2018 forecast pool price.

The 2018 net forecast TFO tariff costs for ATCO Electric are $619.8 million.

(c) **ENMAX** — ENMAX has not yet applied to the Commission for approval of 2018 TFO tariff costs. ENMAX received approval of 2015 TFO tariff costs of $73.9 million in Decision

20819-D01-2015 on November 27, 2015. As well, ENMAX filed for approval of a 2015 deferral account reconciliation shortfall of $1.9 million and has not received a decision as of the filing of this application. ENMAX has filed for approval of 2017 TFO tariff costs of $81.9 million. The AESO has included 72% of the applied for increase of $6.6 million (from the approved 2015 TFO wires costs and 72% of the applied for increase in the 2015 deferral account reconciliation). The AESO has accordingly included $80.1 million as the forecast TFO tariff costs for ENMAX for 2018.

(d) **EPCOR** — EPCOR has not yet applied to the Commission for approval of 2018 TFO tariff costs. EPCOR received final approval of 2017 TFO tariff costs of $98.6 million in Decision 21229—D01—2016. The AESO has accordingly included $98.6 million as the forecast TFO tariff costs for EPCOR for 2018.

(e) **City of Lethbridge** — The City of Lethbridge has not yet applied to the Commission for approval of 2018 TFO tariff costs. The City of Lethbridge received final approval of 2017 TFO tariff costs of $7.1 million in Decision 22136-D01-2016. The AESO has accordingly included $7.1 million as the forecast TFO tariff costs for City of Lethbridge for 2018.

(f) **TransAlta**— TransAlta has not yet applied to the Commission for approval of 2018 TFO tariff costs. TransAlta applied for approval of 2017 TFO tariff costs of $4.9 million. TransAlta received approval for interim 2017 TFO tariff costs of $4.9 million in Decision 22241-D01-2016. The AESO has accordingly included $4.9 million as the forecast TFO tariff costs for TransAlta for 2018.

(g) **City of Red Deer** — The City of Red Deer has not yet applied to the Commission for approval of 2018 TFO tariff costs. The City of Red Deer received final approval of 2017 TFO tariff costs of $4.3 million in Decision 22145-D01-2016. The AESO has accordingly included $4.3 million as the forecast TFO tariff costs for City of Red Deer for 2018.

(h) **FortisAlberta (Farm Transmission)** — Section 32 of the Act requires the AESO to pay owners of electric distribution systems for "farm transmission costs" as defined in the Act. FortisAlberta has not yet applied to the Commission for approval of 2018 TFO tariff costs. FortisAlberta received final approval for 2017 farm transmission costs of $4.7 million in Decision 21980-D01-2016. The AESO has accordingly included $4.7 million as the forecast TFO tariff costs for FortisAlberta for 2018.

41 The wires costs identified above are based on supporting calculations, Commission decisions and TFO tariff applications as set out in Appendix H to this application, *2018 Rate Calculations* at Table H-2.

42 In lines 12-13 of Table H-1 of Appendix H, the AESO includes as wires costs two cost components that are not related to TFOs: Invitation to Bid on Credit costs and Location Based Credit Standing Offer ("LBC SO") costs. These two programs were initiated to provide non-wires solutions for transmission issues in Alberta and their costs are included as wires costs for rate-setting purposes. The $5.4 million cost for the two programs was forecast by the AESO in conjunction with ancillary services costs and has been approved by the AESO Board, as evidenced by the AESO Board Decision included as Appendix A to this application.

3.3 Ancillary services costs

43 Ancillary services, as defined in 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 reserves, which are unloaded generating capacity that is available to respond to temporary shortfalls in supply caused by loss of a generating unit, loss of intertie capacity or fluctuations in load.

44 Ancillary services costs are a function of volume forecasts and market-based commodity pricing forecasts.

45 The 2018 forecast cost for ancillary services is $179.2 million based on the 2018 forecast of ancillary services volumes and a 2018 forecast average pool price of $42.58/MWh. Ancillary services costs represent about 9% of the AESO's revenue requirement in 2018.

3.4 Losses costs

46 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 scheduled exports and less metered loads.

47 Losses costs are a function of volume forecasts and market-based commodity pricing forecasts.

48 The 2018 forecast costs for transmission line losses is $96.8 million based on the 2018 forecast of losses volumes and a 2018 forecast average pool price of $42.58/MWh. Losses costs represent about 5% of the AESO's revenue requirement in 2018.

3.5 Administrative costs

49 The 2018 forecast for administrative costs is $100.8 million and represents approximately 5% of the AESO's revenue requirement in 2018.

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

> *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;*

51 The AESO Board approves the AESO's administrative costs in their entirety, which are allocated among the three functions of the AESO, namely, transmission, energy market, and load settlement. The amounts recovered through the proposed ISO tariff include only the transmission-related portions of the AESO's total administrative costs, as described in paragraph 1(1)(g) of the *Transmission Regulation*.

4 Transmission cost causation

52 The AESO has included its Transmission System Cost Causation 2018 Study Update ("2018 Update") as Appendix D to this application, and supporting analysis in a Microsoft Excel workbook as Appendix E to this application. The 2018 Update and accompanying workbook were completed by the AESO based on the methodology of the 2014-2016 Alberta Transmission System Cost Causation Study ("2014 Study") carried out by London Economics International LLC ("LEI") and are discussed in sections 4.1 and 4.2 below.

53 The AESO is not proposing any changes to the bulk/regional tariff design in this application. The 2018 Update is a mechanical update of 2014 Study, using the latest available information. As stated above, the AESO requested the Commission to direct that the issue of whether the applied-for bulk/regional tariff design should be changed will not be considered in Proceeding 22942.[7] The Commission ruled that "the scope of Proceeding 22942 will not include an examination of the rate design approved in Decision 2014-242 (12 CP method)."[8]

54 The AESO also updated the point of delivery cost function used for determining the point of delivery charge and investment levels in the proposed ISO tariff. The AESO has included, as Appendix G to this application, a point of delivery cost function workbook. The point of delivery cost function is discussed in section 4.3 below.

55 The results of the 2018 Update and updated point of delivery cost function are incorporated into the design of Rate DTS, *Demand Transmission Service*, and other rates are discussed in section 5 of this application.

4.1 Cost causation study background

56 LEI was engaged to prepare the 2014 Study for the 2014 ISO Tariff Application. The 2014 Study was filed on July 17, 2013 as part of the 2014 ISO Tariff Application. An update was filed on November 11, 2013 as part of a negotiated settlement agreement, and another on January 21, 2014, pursuant to the negotiated settlement agreement. The results of the 2014 Study were reflected in the ISO tariff from 2014 to 2018.

57 The AESO 2017 Long-term Transmission Plan does not show the need for any significant transmission facilities that were not included in the 2014 Study. Currently the AESO does not expect any significant transmission facilities that were not included in the 2014 Study to be required by the end of 2020.

4.2 2018-2020 cost causation study update

58 The 2018 Update was undertaken for the 2018 to 2020 period. The 2014 Study, on which the 2018 Update is based, involved analysis in four key areas: (i) functionalization of transmission facility owner ("TFO") related capital costs, for both existing and planned assets (until 2016); (ii) functionalization of related operations and maintenance ("O&M") costs; (iii) classification of all costs functionalized as bulk and regional; and (iv) implementation considerations (i.e. discussion of the potential impact of implementing the functionalization and classification results on rates/recovery of the revenue requirement). The 2018 Update involves an identical analysis using additional data that became available since the time the 2014 Study was performed.

[7] Exhibit 22942-X0128 para 7(b).
[8] Exhibit 22942-X0156 para 33.

59 Functionalization values and classification values from the 2018 Update are set out below in Table 4-1 and Table 4-2, respectively.

Table 4-1 – Bulk, regional and POD functionalization

Function / Year	***2018***	***2019***	***2020***
Bulk	51.4%	52.8%	51.7%
Regional	25.8%	24.5%	24.6%
POD	22.8%	22.7%	23.7%

Table 4-2 – Bulk and regional classification

Class	***Bulk***	***Regional***
Demand related costs	93.4%	89.5%
Energy related costs	6.6%	10.5%

4.3 Point of delivery cost function

60 The design of the point of delivery charge in the AESO's Rate DTS is based on a point of delivery cost function methodology that was established during the 2007 ISO tariff application proceeding. The point of delivery cost function is developed through analysis of actual connection project data. The cost function was updated in the 2010 ISO tariff application and 2014 ISO tariff application, and is updated again in this application.

61 The cost function update included in this application is similar to the methodology directed by the Commission in Decision 3473-D01-2015 in the AESO's 2014 compliance filing and used in the 2014 ISO tariff:

> *The Commission has reviewed the AESO's response to Direction 2 and finds that it has resulted in unanticipated effects that could not have been known at the time of Proceeding 2718. The AESO's proposal to delay the implementation of Direction 2 until the matter can be thoroughly explored is reasonable and both the UCA and Devon agree with this approach.*
>
> *With respect to the 2014 ISO tariff, the Commission finds that the AESO's proposal to use the Rate DTS point of delivery charges and maximum investment levels shown in Table 1 and Table 2 above, described as "Greenfield and Update excluding 0 MW," to be reasonable and approves this approach.*

62 In this application the AESO proposes a change to the applied-for 2014 ISO tariff methodology to include all projects (including 0 MW projects). The exclusion of the 0 MW projects in the 2014 ISO tariff methodology was an interim solution to an issue raised in Proceeding 2718. For the purpose of thoroughly exploring the issue, the AESO has included four point of delivery ("POD") cost function options in Appendix F to this application, which thoroughly explores the four different methodologies, the resulting rates and investment, and an evaluation of the pros, cons and impacts of each option.

63 The AESO is proposing rates and investment levels based on Option #1 – Include Greenfield Projects, Upgrade Projects and Zero MW Projects based on the analysis completed in Appendix F and Appendix V to this application.

64 The AESO has updated the inflation index consistent with the previous methodology approved by the Commission in Decision 2014-242.

4.3.1 Connection project database

65 As mentioned above, the point of delivery cost function is based on data collected for connection projects that result from requests by load market participants for system access service. Connection projects involve the construction of transmission facilities for the connection of a load market participant's facilities to the existing transmission system, and may be either "greenfield" projects or "upgrade" projects. Greenfield projects are those that require the construction of a new substation to provide system access service, while upgrade projects are those that require the construction of additional facilities at an existing substation.

66 Only greenfield projects were included in the connection project data used for the point of delivery cost functions in the 2007 and 2010 ISO tariffs and upgrade project data was also included for the 2014 ISO tariff and this application. More specifically, the project databases used for the different cost functions include:

- 30 greenfield load-only projects with an in-service date ("ISD") in 1999-2008 for the development of the 2007 point of delivery cost function;
- 46 greenfield load-only projects with ISDs in 1999-2009 for the development of the 2010 cost function; and
- 81 greenfield load-only projects and 123 upgrade load-only projects with ISDs in 1999-2014 for the development of the 2014 cost function; and
- 92 greenfield load-only projects and 175 upgrade load-only projects with ISDs in 1999-2017 for the development of the cost function proposed in this application.

67 These projects are referred to as "AESO-era" projects, and represent data points for which the AESO has reasonably detailed facility, cost and contract information.

68 The database used for the development of each of the point of delivery cost functions to date also includes 18 "pre-AESO" load-only projects with ISDs in 1987-1999. The 18 pre-AESO projects were initially included as the smallest and largest projects in the database in order to develop a more robust cost function and have been retained for the same reason, while also adding stability to the cost function through successive tariff applications. The cost and contract information available for pre-AESO projects is very limited.

69 Data for all projects in the connection project database is included in Appendix G to this application. The AESO updated all connection project data to the data most recently available as of June 2017.

70 AESO was directed by the Commission in Decision 2014-242[9] to continue to exclude customer-owned projects from the database and POD cost calculations. In this POD cost function database and POD cost calculations, customer-owned projects were excluded.

[9] Decision 2014-242 at para 20.

71 Table 4-3 summarizes the project data used for the point of delivery cost function in this application and includes comparative information for the project data used for the cost function in the 2014 ISO tariff.

Table 4-3 – Comparison of data used for 2014 and 2018 cost function analysis

	2014 Analysis	***2018 Analysis***
Updated data period	1999-2013	1999-2017
Greenfield projects	99 greenfield projects (81 AESO-era and 18 pre-AESO)	110 greenfield projects (92 AESO-era and 18 pre-AESO)
Cost data source	final costs and PPS estimates where facilities applications have been filed	final costs and PPS estimates where facilities applications have been filed
Total greenfield project costs, inflated	$1,413.6 million	$1,740.9 million
Upgrade projects	123 upgrade projects	175 upgrade projects
Total upgrade project costs, inflated	$434.0 million	$709.8 million

4.3.2 Point of delivery cost classification

72 The point of delivery cost function is used:

(a) to classify costs for the point of delivery charge in Rate DTS; and

(b) to establish investment levels for the construction contribution policy in section 8 (renumbered section 4) of the proposed ISO tariff.

73 Point of delivery cost classification is discussed in the following paragraphs, while investment levels are discussed in section 4.3.3 below.

74 The point of delivery charge in Rate DTS has a five-tier structure, established during the 2007 ISO tariff proceeding. The tiers reflect economies of scale associated with larger connection projects and are determined by plotting specific points on the point of delivery cost function: 1.5 MW, 7.5 MW, 17 MW, 40 MW and 122.8 MW. The AESO uses the forecast billing determinants aggregated over all services within a tier to determine the portion of costs classified in that tier. The resulting point of delivery cost classification is summarized in Table 4-4.

Table 4-4 – Classification of point of delivery costs

Classification	***Customer***	***Demand***				
Tier (MW)	***(Fixed)***	***>1.5 ≤7.5***	***>7.5 ≤17***	***>17 ≤40***	***>40***	***Total***
Cost Function	Cost = $\$2{,}554{,}200 \times MW^{0.5726}$					
Data Point (MW)	1.5	7.5	17	40	122.8	
Cost at Data Point ($ 000 000)	$3.222	$8.097	$12.936	$21.115	$40.136	
Intercept and Slope ($ 000 000)	$2.003	$0.813	$0.509	$0.356	$0.230	
Determinant (cust-mo, MW-mo)	5,309.0	36,498.4	34,526.1	43,063.7	42,896.3	
Classified Costs ($ 000 000)	$10,633.9	$29,673.2	$17,573.8	$15,330.7	$9,866.1	$83,077.6
Cost Classification (%)	12.8%	35.7%	21.2%	18.5%	11.8%	100.0%

75 The AESO proposes the cost function discussed above be applied in the ISO tariff throughout the 2018-2020 period. Maintaining the same cost function will provide a stable basis for the point of delivery charge. The AESO also proposes that ISO tariff updates during the 2018-2020 period would include updated forecast billing determinants to ensure the point of delivery charge continues to recover the appropriate proportions of costs in each tier.

76 Combining the bulk system and regional system cost classification from Table 4-2 and the point of delivery classification from Table 4-4 above provides the overall wires cost classification proposed in this application and summarized in Table 4-5 below.

Table 4-5 – Proposed functionalization and classification of transmission system costs, % of total

		Classification		
Function	***Total***	*Demand*	*Usage*	*Customer*
2018 ISO Tariff				
Bulk System	51.2%	48.0%	3.2%	-
Regional System	26.1%	22.9%	3.3%	-
Point of Delivery	22.7%	21.8%	-	0.9%
Total	**100.0%**	**92.6%**	**6.5%**	**0.9%**

Note: Totals may not add due to rounding.

77 The AESO proposes that this functionalization and classification be applied in the ISO tariff for 2018-2020 period, subject to any adjustment to the point of delivery cost classification resulting from reforecasts of billing determinants during that period.

4.3.3 Determination of local investment

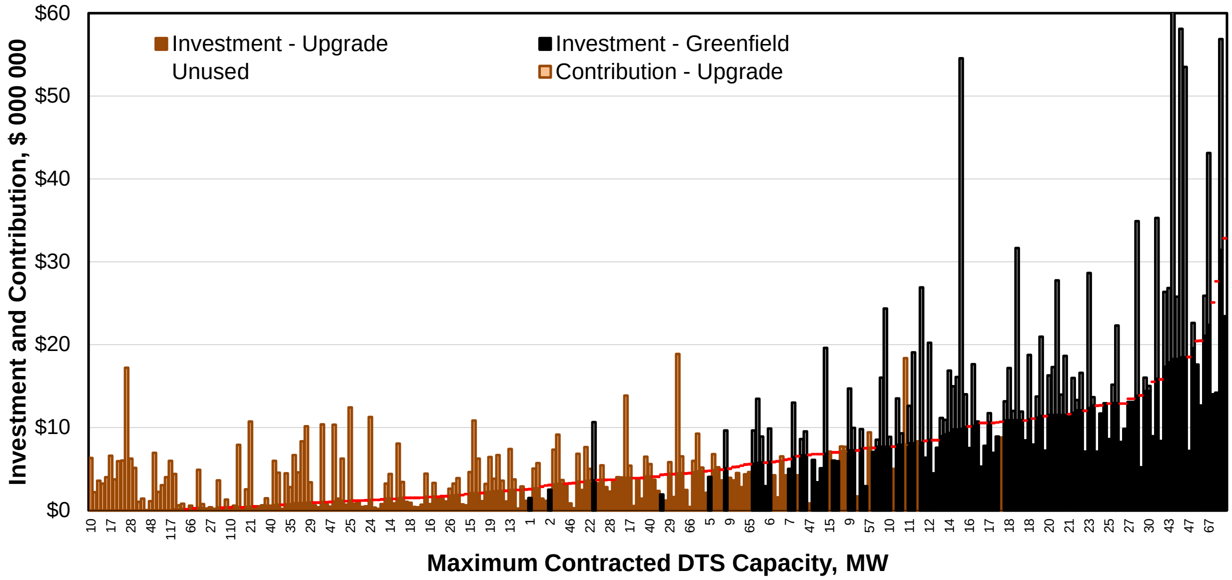
78 The AESO has revised the maximum investment levels provided in proposed section 4 of the ISO tariff, *Classification and Allocation of Connection Projects Costs*, to reflect AESO's examination of contract capacity and installed capacity, and projects costs relationship. This work is discussed above in section 4.3.2 and investment levels are provided in Appendix K to this application

79 This application continues the use of an average cost multiplier methodology to determine maximum investment levels approved in Decision 2012-362[10] on AESO's 2012 Contribution Policy Application. With the update of the connection project database, the multiplier changes from 0.81, approved in the 2014 ISO tariff, to 0.82 to provide an investment coverage level of approximately 60% over all connection projects in the project database. Details of the calculations are in Appendix K to this application. Figure 4-1 below illustrates the investment coverage provided by the proposed investment levels.

80 The calculated investment levels for service under Rate DTS, and under Rate DTS with Rate PSC are included in subsection 4.7(2) of the proposed 2018 ISO tariff in Appendix R to this application, as follows:

[10] Decision 2012-362 at para 49.

Figure 4-1 – Investment coverage chart for proposed investment levels



4.4 Classification of other costs

81 The remainder of the AESO’s revenue requirement comprises of costs related to ancillary services, transmission line losses and the AESO’s own administration. The classification of those costs is proposed to remain as approved in Order U2008-217 for the 2007 ISO tariff, and is provided in Table H-5 in Appendix H to this application.

5 Rate design

82 The rate design used for the proposed ISO tariff was most recently approved in Decision 3473-D01-2015 regarding the AESO's compliance filing made pursuant to Decision 2014-242, resulting in rates and riders that became effective on July 1, 2015. The principles and methodologies for the AESO's current rate design approved in that decisions have been used for the rates and riders proposed in this application.

83 The rates and riders proposed in this application also reflect the continued alignment of the ISO tariff with the AESO's other authoritative documents (namely, ISO rules and Alberta reliability standards). In particular, the language of the rates and riders in the proposed ISO tariff has been updated, where appropriate, to reflect the AESO's current practices set out in its authoritative documents.

84 Other than changes to reflect the transmission cost causation studies completed for this application, as discussed in section 4, only limited changes are proposed for the rates and riders in this application.

85 The specific changes proposed for rates and riders in this application include the following:

(a) All rate levels have been updated to recover the 2018 forecast revenue requirement detailed in section 3 of this application based on the AESO's 2018 forecast billing determinants;

(b) The functionalization and classification of transmission wires costs have been updated to reflect the findings in the 2018 Update and the updated point of delivery cost function discussed in section 4 of this application;

(c) Section 7(b) of Rate DTS and Rate FTS has been updated to waive the power factor deficiency charge if such a charge had been waived by the ISO prior to December 31, 2016. As well, the AESO is proposing to increase the power factor deficiency charge from $400/MVA to $1,200/MVA. These changes are discussed further in section 5.4.1 of this application;

(d) A provision has been added to Rate PSC, *Primary Service Credit*, to ensure that Rider C, *Deferral Account Adjustment Rider*, is applicable to Rate PSC as discussed further in section 6.1 of this application;

(e) Rider A1, *Transmission Duplication Avoidance Adjustment – Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2*, has been extended from December 31, 2021 until December 31, 2041 to reflect an expected forty year-life of transmission facilities discussed in section 6.2 of this application;

(f) Revisions to Rider C, *Deferral Account Adjustment Rider*, discussed further in section 6.1 below, include revisions to the applicability section to include Rate PSC, *Primary Service Credit*; for Rider C to become a percentage charge or credit (previously a $/MWh charge or credit); to restore deferral account balance to zero at the end of the calendar year; and for Rider C to become applicable to the sum of the connection charge and the primary service credit; and

(g) Refinements and updating of language and provisions throughout the rates and riders for consistency with current requirements and guidelines as set out in the AESO's authoritative documents.

86 The AESO is not proposing any changes to Rider F, *Balancing Pool Consumer Allocation Rider*, and Rider J, *Wind Forecasting Service Cost Recovery Rider,* in this application. Rider F was updated for

2018 and approved by the Commission in Decision 23163-D01-2017 on December 15, 2017. Rider J was updated in the 2018 ISO Tariff Update Application and approved by the Commission in Decision 23065-D01-2017 on November 28, 2017. Rider F will be updated for 2019 in a separate application in Q4 2018 and Rider J will be updated in the 2019 ISO tariff update application to be filed in Q4 2018.

87 Changes that affect the intent or content of the rates and riders of the proposed ISO tariff are described in more detail in sections 5.4 and 6 of this application. The rate calculations reflecting the rate design considerations discussed in this section are provided in Appendix H to this application. The format of the rate calculations in Appendix H follows the format used in previous ISO tariff applications.

88 The effect on the rates as a result of the changes proposed in this application is a net average decrease of 4.0% in Rate DTS and a net average decrease of 15.7% in Rate STS, *Supply Transmission Service*, compared to the rates approved in the 2017 ISO tariff update. However, not all components of Rate DTS and Rate STS are affected equally, and changes by component of both are summarized in Table 5-1 below.

Table 5-1 – Change by rate component, 2017 ISO tariff update to 2018 calculated rates

	Increase (Decrease)	
Rate component	*DTS*	*STS*
Bulk System Charge	(15.6%)	–
Regional System Charge	11.9%	–
POD Charge	15.4%	–
Connection Charge	(3.5%)	–
Operating Reserve Charge	(7.9%)	–
Transmission Constraint Rebalancing Charge	(97.1%)	–
Voltage Control Charge	28.6%	–
Losses Charge	–	(15.4%)
Other System Support Services Charge	-	–
Regulated Generating Unit Connection Costs	–	(21.1%)
Total Effect on Rate	(4.0%)	(15.7%)

89 These changes reflect the net effect of both changes to the AESO's revenue requirement and changes in billing determinants from the 2017 forecast on which the 2017 ISO tariff update was based and the 2018 forecast on which the rates in this application are based. The bill impacts presented in Table 5-1 are average bill impacts overall system access services. The impact of changes to rates and rate levels on individual system access services is discussed in section 5.6 below and provided in more detail in Appendix I to this application. For additional context, section 5.7 below and Appendix J to this application provide a long-term projection of transmission rates.

5.1 Legislative requirements

90 The AESO is a not-for-profit statutory corporation established by section 7 of the Act and provides system access service to market participants pursuant to section 29 of the Act. As part of its transmission responsibilities, the AESO must prepare and receive approval of rates and terms and conditions in accordance with sections 30 and 119 of the Act, which provides:

ISO tariff

30(1) The Independent System Operator must submit to the Commission, for approval under Part 9, a single tariff setting out

(a) the rates to be charged by the Independent System Operator for each class of system access service, and

(b) the terms and conditions that apply to each class of system access service provided by the Independent System Operator to persons connected to the transmission system.

Preparation of tariffs

119(4) The Independent System Operator must prepare a tariff relating to the transmission system in accordance with Part 2 and apply to the Commission for approval of the tariff.

91 Additional requirements regarding the recovery of transmission system costs through rates charged by the AESO for system access service are prescribed by the *Transmission Regulation*, which provides:

Intertie projects

27(4) The cost of planning, designing, constructing, operating and interconnecting an intertie to which this section applies must be paid by

(a) the person proposing the intertie, and

(b) other persons to the extent that they directly benefit from the intertie, based on the use described in the needs identification document approved by the Commission, and then only to the extent permitted by the ISO tariff.

27(6) The ISO must include in the ISO tariff, rates and terms and conditions that include costs for use of the interconnected electric system, appropriate for the class of service provided to persons who use the intertie referred to in this section for import or export of electric energy to or from Alberta.

Adjustment of loss factors

33(1) In accordance with the ISO rules, loss factors may be adjusted by a calibration factor to ensure that the actual cost of losses is reasonably recovered through charges and credits under the ISO tariff on an annual basis.

Recovery of transmission losses

34 In accordance with the ISO rules, the cost of transmission line losses must be reasonably recovered using the loss factors determined under section 35 or 36 as those loss factors are charged or credited to the persons referred to in section 31(1)(e) under the ISO tariff.

[Section 31(1)(e) refers to:

(i) owners of generating units,

(ii) importers and the exporters of electricity, and

(iii) any other opportunity service customers referred to in clause (a)(iv) [any other opportunity service customer in respect of whom the ISO determines a loss factor is to apply]]

ISO tariff - transmission system considerations

47 When considering an application for approval of the ISO tariff under sections 121 and 122 of the Act, the Board must

(a) ensure

(i) the just and reasonable costs of the transmission system are wholly charged to DFOs, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff, and

(ii) the amount payable by a DFO is recoverable in the DFO's tariff,

(b) ensure owners of generating units are charged local interconnection costs to connect their generating units to the transmission system, and are charged a financial contribution toward transmission system upgrades and for location-based cost of losses, and

(c) consider all just and reasonable costs related to arrangements and agreements described in section 9(5) of the Act.

92 In accordance with section 47 of the *Transmission Regulation*, the AESO has allocated all costs of the transmission system, except for losses and Regulated Generating Unit Connection Cost ("RGUCC"), to load services and exporters. RGUCC continues to be allocated to regulated generators "to place existing generation on the same competitive basis as new generation," as directed by the Alberta Energy and Utilities Board ("EUB"), predecessor to the Commission, in Decision 2000-1 concerning the ESBI Alberta Ltd. 1999/2000 General Rate Application Phase 1 and Phase 2.

93 In accordance with section 34 of the *Transmission Regulation*, the cost of transmission losses is allocated to generators, export and import services, and demand opportunity service. Rider E, *Losses Calibration Factor Rider*, also applies to those services as required by section 33(1).

94 The allocation of costs to load and supply services is summarized in Appendix H Table H-3, and the related allocation of ISO tariff revenue offsets.

5.2 Rate design principles

95 In its 2006 ISO tariff application, the AESO identified five rate design principles applicable to a utility (adapted from *Principles of Public Utility Rates* by Bonbright, Danielsen, and Kamerschen, 2nd ed., 1988, pp. 385-389):

(i) recovery of the total revenue requirement;

(ii) provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service;

(iii) fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;

(iv) stability and predictability of rates and revenue; and

(v) practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable.

96 The application of these principles to the AESO's rate design was extensively discussed in both Decision 2005-096 on the 2005-2006 ISO tariff application and in Decision 2007-106 regarding the 2007 ISO tariff application. Those decisions noted the following:

(a) The first principle would be satisfied by any rate design that, on a forecast basis, recovered the applied-for revenue requirement.

(b) The second and third principles were considered to be satisfied by rates which recover costs in the manner in which they are caused. That is, rates based on cost causation should provide appropriate price signals, should be fair, objective, and equitable, and should minimize or eliminate inter-customer subsidies. Cost causation therefore is the primary consideration when evaluating a rate design proposal.

(c) The remaining two principles were considered to be given secondary consideration. That is, there should be little need to be concerned about stability and of practicality if rates reflect cost causation, barring unusual regulatory events such as regulatory lag or dramatic changes in cost structure.

97 Decision 2010-606 regarding the 2010 ISO tariff application reaffirmed that after the principle of full recovery of the revenue requirement, a rate design reflecting cost causation should generally prevail over other secondary considerations, including rate shock considerations, when assessing the AESO's rate design.

98 The AESO has accordingly continued to apply in this application the cost causation principles used by the AESO for its rates. In particular, and as discussed above, the AESO has relied on the Transmission System Cost Causation Study and the updated point of delivery cost function to improve the functionalization and classification of costs for the proposed rates.

5.3 Rate design considerations

99 As stated above, the Commission ruled that the scope of Proceeding 22942 will not include an examination of the rate design approved in Decision 2014-242 (12 CP method).

5.4 Proposed rate changes

100 Other than changes to reflect the 2018 forecast revenue requirement and the updated functionalization and classification of transmission wires costs, described in Table 4-5 above, the AESO is proposing only limited changes to the 2018 rates and riders in this application. Proposed changes to specific rates and riders are discussed in the following paragraphs.

5.4.1 Rate DTS, Demand Transmission Service, other system support services charge revision

101 The current subsection 7(b) of Rate DTS currently includes a power factor deficiency charge as follows:

7 *The **ISO** must determine the other system support services charge as the sum of: …*

*(b) when **power factor** is less than 90% during the interval of highest **metered demand** in the **settlement period**, $400.00/MVA multiplied by the **apparent***

***power** difference calculated during the interval of highest **metered demand** in the **settlement period** as the difference between the metered **apparent power** and 111% of **metered demand**.*

102 In general, the transmission system must be capable of serving both the real (MW) and reactive (MVAr) power needs of market participants. Rate DTS recovers the costs of the transmission system primarily on a real power (MW) basis, including facilities sufficient to serve reasonable reactive power needs. In the case of the ISO tariff as well as the tariffs of most DFOs, reasonable reactive power needs are those that result in a power factor of 90% or higher. Costs of serving reactive power needs that arise from power factors of less than 90% are recovered through the power factor deficiency charge.

103 The power factor deficiency charge provides an incentive for load market participants to manage their reactive power requirements such that power factor is at least 90% at the point of delivery. The 90% threshold aligns with similar thresholds in the tariffs of most DFOs. The 90% threshold has existed in tariffs charged for system access service to loads since the restructuring of the electric industry in Alberta in 1996.

104 The incentive provided by the power factor deficiency charge appears to be reasonably effective. Fewer than 20% of monthly Rate DTS invoices include power factor deficiency charges. When included, more than three-quarters of the charges are for apparent power amounts of 1 MVA or less.

105 The power factor deficiency provision of Rate DTS applies to all system access services for market participants with load-only facilities. However, the application of power factor deficiency charges to certain load sites that include limited generation facilities has historically been waived by the AESO. Such waivers were initially implemented for DFOs with distribution-connected generation, where such generation was not under the control of the DFO.

106 At that time, the AESO considered the waiver to be consistent with the intent of the power factor deficiency provision, where the DFO had ensured that load facilities connected to its distribution lines had an aggregate power factor of 90% or higher but the interaction of the distribution-connected generation resulted in the measurement of a lower power factor at the transmission point of delivery. The load facilities and the distribution-connected generation facilities would each independently comply with the thresholds and requirements of the AESO (90% or greater power factor for load; 90% power factor lagging and 95% power factor leading at the generator unit terminals for generation) but in combination appeared to exceed the load threshold.

107 The interaction of the load and generation facilities is illustrated in Table 5-2 below.

108 In waiving the power factor deficiency charge at such sites, the AESO considered that the load facilities did not exceed the power factor threshold of Rate DTS and the DFO had limited or no control of production from the distribution-connected generation. Over time, the waiving of power factor deficiency charges was also granted at some services where load and generation facilities were owned by the same market participant but were otherwise similar in configuration to the example illustrated in Table 5-2 below.

Table 5-2 – Power factors for load and generation at a point of delivery

Facilities	Real Power	Reactive Power	Apparent Power	Power Factor	Comments
	MW	MVAr	MVA	%	
Load	20.0	8.0	21.5	93%	Above 90% threshold
Generation	(10.0)	(2.0)	(10.2)	(98%)	Above 90% lagging requirement
Combined	10.0	6.0	11.7	86%	Below 90% threshold

Note: Positive power flow is from the transmission system to the distribution system

109 After receiving a recent request for a power factor deficiency charge waiver, the AESO revisited this matter, and has concluded that the delivery of reactive power to a point of delivery represents an obligation for the AESO, regardless of what causes the downstream requirements for reactive power. Such an obligation may result in the incurrence of costs on the transmission system, and such costs should generally be attributed to the "causer" of the reactive power requirement that the AESO is addressing. The AESO also considers that there are options available to a distribution system owner to address net reactive power required from the transmission system, including additional incentives for its end-use consumers or distribution-connected generators to further manage their reactive power requirements or through installation of reactive power devices on the electric distribution system.

110 The AESO will therefore no longer waive power factor deficiency charges at load sites with downstream generation, whether for a DFO or direct-connected end-use consumer.

111 The AESO recognizes that those market participants who previously received power factor deficiency charge waivers may face additional costs in addressing power factor deficiency, compared to connections of new facilities. The AESO accordingly proposes to "grandfather" services at which waivers had been previously granted and allow those waivers to continue in effect indefinitely.

112 The AESO proposes to add an explicit grandfathering provision for power factor deficiency charge waivers to Rate DTS as follows:

> ***7*** *The **ISO** must determine the other system support services charge as the sum of: …*
>
> *(b) when **power factor** is less than 90% during the interval of highest **metered demand** in the **settlement period**, $400.00/MVA multiplied by the **apparent power** difference calculated during the interval of highest **metered demand** in the **settlement period** as the difference between the metered **apparent power** and 111% of **metered demand**<u>, unless the **ISO** had waived the application of such a charge prior to December 31, 2016</u>.* [underlining added]

113 The AESO proposes a grandfathering end date of December 31, 2016, as no power factor deficiency charge waivers have been granted by the AESO since that date. The AESO does not propose that grandfathered waivers should expire at a specific date, as the cost of addressing power factor deficiencies after facilities have been constructed could remain significantly higher than the cost of doing so when initial decisions regarding configuration were being made.

114 The power factor deficiency charge has remained at $400/MVA since the charge was implemented in the tariff of Gridco, a predecessor of the AESO, in 1996. The AESO has accordingly reviewed the magnitude of the charge in conjunction with reviewing the application of the charge as discussed above.

115 In general, the power factor deficiency charge would be expected to increase in conjunction with transmission facility costs, as both real power and reactive power are supplied through the same facilities, and those facilities must be sufficient to supply the total apparent power needs of market participants. As the level of charges for real power have increased materially since 1996, the level of the power factor deficiency charges would be expected to have increased as well.

116 Issues arising from power factor deficiency may be addressed in multiple ways, including the replacement or reconfiguring of equipment by the market participant; the installation of capacitors by the market participant; or the installation of capacitors on the transmission system by the AESO. The most technically efficient approach may be to reduce the need for reactive power by the replacement or reconfiguring of the market participant's equipment. However, in certain instances the most economically efficient approach may be the installation of capacitors by the AESO, as the capacitors may address power factor issues for multiple market participants.

117 The ISO tariff should appropriately recover the cost of transmission capacitors through Rate DTS, to ensure that appropriate price signals are provided to market participants who can then make decisions to manage their reactive power requirements. The AESO has examined the cost of adding capacitor banks on the transmission system, the power factor deficiency charges in distribution system owner tariffs, and the cost of a market participant adding capacitors on its own facilities, and has concluded the power factor deficiency charge should be increased to $1,200.00 per MVA of apparent power.

118 The AESO further proposes that the power factor deficiency charge be indexed to the weighted average increase in transmission system costs in future ISO tariff applications and ISO tariff updates, to ensure that the price signal provided by the power factor deficiency charge remains appropriate.

5.5 2018 forecast billing determinants

119 The rate calculations for this application are based on the AESO's forecast of billing determinants for 2018. 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 2017 LTO and included in Appendix N to this application.

120 The 2017 LTO includes a 20-year peak load and electricity consumption forecast for Alberta. The load forecast is generated from economic growth (gross domestic product or GDP) information, oilsands production forecasts, and population projections by select consumer sectors, with regional adjustments based on historical results and participant-driven growth expectations. The 2017 LTO, including its data file, is available on the AESO website at www.aeso.ca by following the path Grid ▶ Forecasting and is provided as Appendix N to this application.

121 Billing determinants are calculated using historical and year-to-date ratios between DTS Energy and each individual billing determinant listed below in Table 5-3. The billing determinants used in the 2018 rate calculations are also provided in Table H-12 of Appendix H to this application.

122 Additionally, Table 5-3 below provides a comparison of the forecast billing determinants in the proposed ISO tariff to the recorded values for 2017, 2016, 2015 and 2014. Coincident metered demand and energy billing determinants for the 2018 forecast have increased by 3.4% and 2.2% respectively compared to the 2017 recorded billing determinants, while the number of DTS market participants has increased by 0.5%. Billing capacity (which incorporates non-coincident metered demand, demand ratchets, and contract minimums) has increased by 1.1%, with a 0.6% increase in the first demand tier, an increase of 1.9% in the second demand tier, an increase of 1.7% in the third demand tier and an increase of 0.3% in the last demand tier.

Table 5-3 – Forecast and billing determinants for 2014-2018

Rate DTS Billing Determinant	Units	2018 Forecast	2017 Recorded	2016 Recorded	2015 Recorded	2014 Recorded
Coincident metered demand	MW-months	97,697.5	94,486.6	92,111.9	93,932.2	93,944.8
Billing Capacity						
• Total billing capacity	MW-months	156,984.4	155,274.4	151,464.1	150,192.2	145,823.1
• First (7.5×SF) MW	MW-months	36,498.4	36,283.5	35,955.3	35,719.7	35,113.6
• Next (9.5×SF) MW	MW-months	34,526.1	33,881.2	33,070.3	32,722.6	31,887.3
• Next (23×SF) MW	MW-months	43,063.7	42,362.5	41,278.9	40,893.2	39,114.9
• All remaining MW	MW-months	42,896.3	42,747.1	41,159.6	40,856.7	39,707.3
Highest metered demand	MW-months	122,370.3	120,536.9	115,502.5	117,088.4	116,686.7
Metered energy (all hours)	GWh	61,303	60,010	58,504	58,942	58,973
DTS market participants	cust-months	5,309.0	5,283.2	5,255.7	5,237.1	5,148.4
Pool price	$/MWh	42.58	22.19	18.28	33.34	49.42

5.6 Bill impacts

123 In its 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 application, and is provided as Appendix I.

124 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.

125 For this application, the AESO has accordingly compared, on a per-point-of-delivery basis, bills under the proposed 2018 Rate DTS to bills under the 2017 Rate DTS presented in section 4 of this application. 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.

126 The bill impact analysis was based on an extract of actual market participant billing determinants for each Rate DTS point of delivery from January 2014 to December 2016, including coincident metered demand, substation fraction, and actual pool price for metered energy at the point of delivery.

127 For the comparison, the proposed 2018 Rate DTS and the 2017 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.

128 Table 5-4 provides the distribution of total bill increases over the 552 points of delivery included in the analysis. The AESO notes that operating reserve charges and the transmission constraint rebalancing charge under the proposed 2018 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 I to this application.

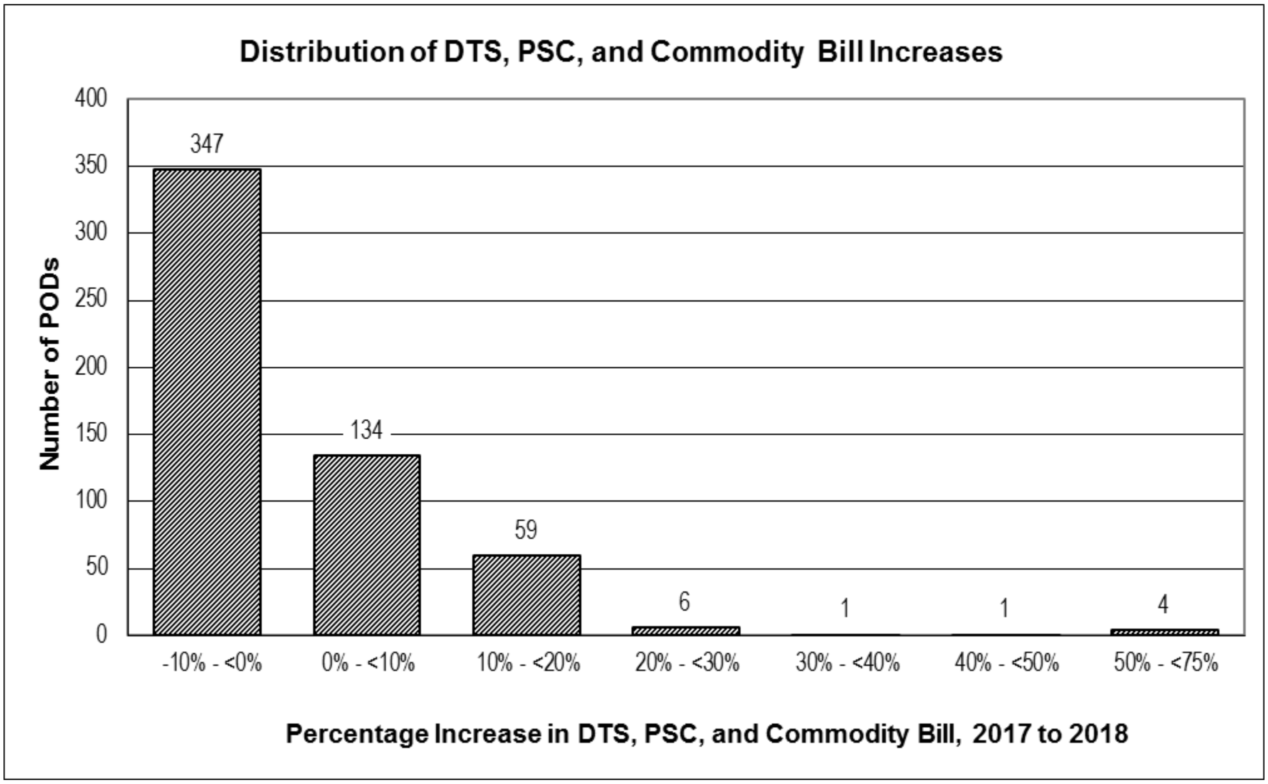
Table 5-4 – Summary of average per-POD bill impacts

Description	*Billing Capacity*				*Total*
All Load Factors	***0 to <7.5***	***7.5 to <17***	***17 to <40***	***40 to 183***	
Number of Accounts	154	153	152	93	552
Monthly Usage (MWh)	951	4,746	10,703	25,409	8,809
Average Billing Capacity (MW)	3.1	12.0	26.7	67.3	22.9
Load Factor (%)	35%	54%	54%	54%	49%
2017 Monthly Bill ($)	$57,950	$250,466	$550,032	$1,257,431	$448,898
2018 Monthly Bill ($)	$58,807	$247,781	$538,568	$1,223,031	$439,440
2017-2018 Increase ($)	$858	($2,684)	($11,464)	($34,400)	($9,457)
2017-2018 Increase (%)	7.7%	0.0%	(0.9%)	(1.3%)	1.7%

129 As illustrated in Figure 5-1 below, the majority of Rate DTS points of delivery (347 points of delivery, or about 63%) receive decreases of zero to 10% based on Rate DTS charges, Rate PSC credits and commodity costs. In addition:

- 134 points of delivery (about 24% of the total) received increases from zero to +10%, and
- 59 points of delivery (about 11% of the total) receive increases from +10% to +20%.

Figure 5-1 – Distribution of DTS, PSC and Commodity Bill Increases



130 Decision 2007-106 directed that services receiving an increase greater than 10% be examined in more detail. Table I-6 in Appendix I accordingly provides additional information on the 71 services receiving increases greater than 10% due to the proposed 2018 Rate DTS. Of those services, 25 (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."[11]

131 The AESO further notes that all 71 services receiving greater than 10% increases have very low billing capacity or very low load factors. Load factors for the 71 sites average only 10%. Disregarding dual-use sites, only 10 of 46 load only sites have a load factor of over 10%. Out of these 10 DFO sites, five are isolated sites serving remote communities with billing capacity of 0.016 MW to 0.122 MW and two are very small services with billing capacity of 0.002 MW each. Remaining three services have billing capacity of 0.193 MW, 0.27 MW and 1.377 MW. These three services receive bill increases of 10.6% to 13.7%. These low billing capacities or low load factors result in the larger-than-average increases at these sites due to two effects:

(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; and

[11] Decision 2008-037 at page 6.

(b) 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 5-1 above and more detail in Table H-13 in Appendix H of this application.

132 The bill impacts provided in Appendix I and summarized in Table 5-4, above, and Figure 5-2, below, result from rates based on cost causation as discussed in section 4 of this application. 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 2018 Rate DTS.

133 Finally, the AESO notes that the bill impact analysis presented in Appendix I is an estimate of the impact of the proposed 2018 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.

5.7 Long-term transmission rate projection workbook

134 The AESO included a Long-term Transmission Rate Projection as Appendix J of the 2014 ISO tariff application which projected transmission costs and Rate DTS to 2031. In Decision 2014-242 (paragraph 422 page 83), the Commission found "the AESO's current practice to be helpful and the AESO is therefore directed to continue its current practice of providing its long-term transmission rate projections".

135 The AESO included a transmission rate projection workbook ("TRP workbook") as Appendix J[12] to the originally filed 2018 ISO tariff application. The AESO filed an updated TRP workbook on April 27, 2018[13] ("updated TRP workbook" or "update"). This updated TRP workbook primarily incorporates the AESO 2017 Long-term Transmission Plan capital costs and schedules along with the latest pool price, trading charge, inflation and operating reserve costs information. It also provides context for changes to Rate DTS over a 20 year period. The updated TRP work book incorporates the most recent information available as of Q1 2018 and allows assumptions to be varied to test the sensitivity of the projection to changes in those assumptions. It also allows example billing determinants to be varied to provide a projection of specific bills for individual load characteristics.

136 The TRP workbook and update assume the functionalization and classification of transmission costs continues into the future as proposed in this application for 2018 and 2019-2020. The TRP workbook and update also assume that the design and structure of Rate DTS will be unchanged from the proposals reflected in this application.

137 Future changes to any of these or other rate design assumptions in the TRP workbook and update will affect the costs projected for the example service included in the TRP workbook and update. The inclusion of the rate design and other assumptions in the TRP workbook and update is not meant to indicate any predetermination of the result of any TFO or ISO tariff proceeding, nor to be interpreted as AESO support for any specific proposals or approaches included in a TFO tariff application.

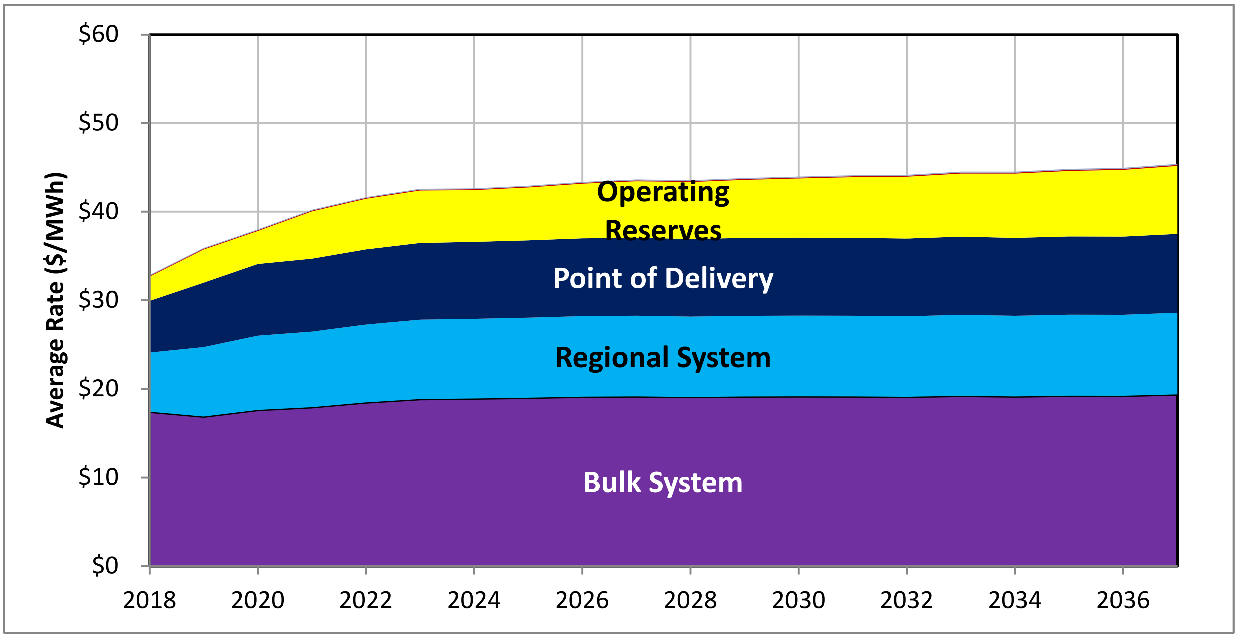
138 The AESO is not requesting approval of the TRP workbook or update in this proceeding. In this proceeding, the AESO is requesting approval of rates for 2018. Rates for subsequent years will be applied for when more specific forecasts of costs and billing determinants are available than those included in the TRP workbook and update. The TRP workbook and update is provided for information

[12] 22942-X0006, Appendix J - Transmission Rate Projection Workbook.
[13] 22942-X0126, Updated Transmission Rate Projection Workbook.

in response to the Commission's comments quoted above, in response to stakeholder requests for such a projection, and as additional analysis related to the AESO's periodic filing of its long-term transmission plan.

139 Although not seeking approval of the TRP workbook or update, the AESO considers the projection to offer useful context in which to review the rate changes proposed in this application and in the longer term.

Figure 5-2 – Average transmission rate by component ($/MWh)



140 The AESO observes that change in average rate by component is largely gradual. The AESO expects changes beyond 2020 (the final year of the proposed ISO tariff) to be similarly gradual in nature.

141 The AESO reiterates that the TRP workbook and update are not meant to imply the Commission will approve such rates in the future or that costs incurred by the TFOs or the AESO will exactly follow the assumptions in the projection. The TRP workbook and update are based on many assumptions as documented within the workbooks. Although the AESO has made best efforts to include reasonable values for those assumptions, actual values are expected to vary from the assumptions in the future.

6 Riders

6.1 Rate PSC, *Primary Service Credit*, and deferral account reconciliation methodology changes

142 In Decision 2014-242 regarding the AESO 2014 ISO tariff application and 2013 ISO tariff update, the Commission directed the AESO regarding Rider C and deferral account reconciliation:

> *The Commission acknowledges the view expressed by both the ADC [Alberta Direct Connect Consumers Association] and the DUC [Dual Use Coalition] that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA [general tariff application], and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA.*[14]

143 In Decision 21735-D02-2017 regarding the AESO 2015 deferral account reconciliation, the Commission provided the following further direction:

> *Nonetheless, the Commission expects the AESO to follow through on its commitment to further consult with stakeholders on this issue and directs the AESO to address whether changes to the deferral account allocation methodology and to Rider C are warranted given the concerns raised by the PS Group, as part of its next ISO tariff application.*[15]

144 The AESO has fully responded to both directions in its *Report on Examination of Rider C and Deferral Account Reconciliation Methodology* provided as Appendix L to this Application. That report provides the background, examination, and conclusions of the AESO that have resulted in the following proposed changes to Rider C and the AESO's annual deferral account reconciliation methodology.

145 The AESO initially notes that, as a result of its examination of deferral account matters, it has accelerated its filing of ISO tariff update applications. Early filing of ISO tariff updates should improve the correlation in the approved ISO tariffs between the cost basis for revenue and forecast current year costs and, by doing so, should reduce the imbalances that would otherwise result from deferral account reconciliations. No specific applications or approvals were required to implement early ISO tariff updates; the AESO simply accelerated the pace of ISO tariff update applications.

146 As a result of its examination of deferral account matters, the AESO also proposes the following three changes to Rider C and has provided the bases for proposing these changes in the report provided as Appendix L to this application:

(a) First, Rider C is proposed to be determined as an additional percentage charge or credit that applies to each of the components of Rates DTS and FTS, rather than as an additional $/MWh charge or credit as currently approved;

(b) Second, Rider C is proposed to be calculated to minimize year-end deferral account balances, rather than to minimize balances at the end of the upcoming calendar quarter as currently approved. Rider C will continue to be set on a quarterly basis, but will be calculated every quarter to recover or refund all accumulated and forecast differences between anticipated costs and actual costs on a calendar year basis. The AESO proposes to continue

[14] Decision 2014-242 at para 704.
[15] Decision 21735-D02-2017 at para 108.

to have the discretion to recover or refund such differences over a longer period to minimize rate impact; and

(c) Finally, Rider C is proposed to also apply to Rate PSC, also as an additional percentage charge or credit.

147 The AESO's examination of Rider C supports the conclusions that these changes will, on a forecast basis, eliminate all imbalances between market participants that result after a deferral account reconciliation. The AESO cautions that some events may still occur that will result in imbalances between market participants, but suggests that the effect of such events cannot be avoided. The AESO further suggests that any such impacts be reviewed after experience is gained following implementation of the Rider C and deferral account reconciliation methodology changes proposed in this application.

(a) As a result of its examination of deferral account matters, the AESO proposes two complementary changes to its deferral account reconciliation methodology: First, the deferral accounts are proposed to be reconciled on a production year basis, rather than on a production month basis as currently approved. This change aligns with the proposed calculation of Rider C to minimize year-end deferral account balances; and

(b) Second, deferral account balances are proposed to be allocated based on revenue by rate component of Rates DTS and Rate FTS, net of credits of Rate PSC. This change aligns with the proposed application of Rider C to Rate PSC.

148 The revisions to implement these proposed changes have been included in the proposed 2018 ISO tariff provided as Appendix R to this application.

149 In Decision 22942-D01-2017, issued on November 28, 2017, the Commission approved the AESO's request for interim approval of the proposed changes to the deferral account reconciliation methodology, Rider C and Rate PSC. Those changes have been implemented in the ISO tariff on an interim refundable basis effective January 1, 2018, and will be subject to adjustment following the final decision on the deferral account reconciliation methodology, Rider C and Rate PSC matters after the full regulatory review of this application.

150 The AESO expects the changes that have been approved on an interim basis will reduce imbalances between market participants that have occurred in prior deferral account reconciliations, consistent with the direction issued to the AESO in Decision 2014-242. The changes will also address probable and material impacts that would otherwise be expected by certain market participants, including those who have been subject to material imbalances in prior deferral account reconciliations as well as those who receive primary service credits. The AESO considers that the interim approval has enabled prompt and accurate allocation of deferral account balances to market participants, and, in the AESO's view, is rendering reasonable results in the immediate term and will continue to do so in the longer term.

151 The ISO tariff revisions to implement these proposed changes on an interim basis are provided in both clean versions, in Appendix R to this Application, and blackline versions, in Appendix S to this application.

6.2 Rider A1, *Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2*, extension

152 In Decision U98125, issued July 24, 1998, the EUB approved a transmission duplication avoidance ("DAT") rate rider for Dow Chemical Canada Inc. ("Rider A1"). The Rider A1 forecast benefit table expires in 2021. The AESO is proposing to extend the rider and, accordingly, the AESO is applying to

extend Rider A1 for an additional 20 years, to 2041, and to update the rider and various terms and conditions of the rider.

153 In the AESO's view, an application to extend the term of the rider should not require an evaluation with reference to the four criteria generally used for evaluating a proposed DAT rate rider. Rather, the AESO proposes that an evaluation referencing the four criteria should be deferred until (i) the end of life of the original credible bypass threat occurs; and (ii) the AESO has reapplied for approval of a DAT rate rider for the facility. In Decision 2001-68, the EUB expressed caution for committing other customers to special tariffs for lengthy (30-35 years) periods, when the benefit received by customers is relatively minor and no real investment by the proponent is being made. As the lifespan of the type of assets in the DAT rider applications generally exceed this time frame, applications for extensions to terms will be necessary and should be dealt with in a regulatory efficient manner.

154 While Rider A1 does not contain language regarding extension of the term, the AESO is guided by the EUB's statements in Decision 2002-019:

> *FIRM submitted that IOL [Imperial Oil Limited] should not have the discretion to extend the DAT beyond the end of its proposed 29-year Term. Since circumstances might change over the Term of the DAT, FIRM submitted that any extension of the DAT should only occur by agreement between both parties. FIRM also considered that the TA should make no commitment to limit consideration of the costs of any extension of the Term of the DAT.EAL [a predecessor of the AESO] appeared to agree with FIRM.*
>
> *However, the Board is concerned that, as presently proposed, the DAT may not reflect and address these concerns. Therefore, the Board directs EAL to incorporate into the DAT language expressly providing that any extension of the Term of the DAT must be by agreement between the parties with notice to the Board and interested parties. This would provide adequate opportunity for a review of the reasonableness of the extension. Interested parties will have the opportunity to review the language proposed by EAL before final approval of the DAT.*

155 In summary, the EUB identified that any extension of term of the DAT should be:

- by agreement between the parties;
- with notice to the Commission and interested parties; and
- reasonable.

156 The AESO can confirm that both the AESO and Dow Canada Inc. wish to extend the term of the Rider A1. The AESO submits that notice is satisfied by inclusion of the AESO's request to extend the term of Rider A1 in this application.

157 The AESO is proposing to extend Rider A1 by 20 years. The term of Rider A1, including the proposed 20 year extension, falls within the estimated lifespan of the bypass, had it been built. As Dow Canada Inc. has already paid the capital cost of the proposed bypass, the AESO considers it reasonable for the rate rider to be limited to only operations and maintenance cost and losses cost during the 20 year extension.

158 The AESO has revised the forecast benefit table to include the years 2022 through to 2041 by carrying forward the annual operations and maintenance cost, annual spares replacement cost, overhead and losses of $191,250 from 1998 to 2022 dollars (inflated by Alberta Consumer Price Index "CPI", aggregate CPI of 1.745) and performed the same calculations as applied for in original DAT application to calculate the annual value, in 2022 dollars, of other expenses and losses of $36,213. The annual amounts for years 2023 through 2041 were inflated by Alberta CPI. The forecast benefits for 1998 through to 2021 have been removed from the table to reflect that Dow Canada Inc.

made the forecast benefit payments as two monetary contributions totaling $5,071,038, consisting of (i) $4,656,038 in capital costs and (ii) $415,000 in future operating and maintenance costs, losses and spare inventory costs to TransAlta in 1997 and 1998.

159 In the AESO's view, the DAT rider term extension achieves the optimal financial outcomes for market participants in the circumstances and also results in efficient use of existing transmission assets.

6.3 Rider J, *Wind Forecasting Service Cost Recovery Rider*, updates

160 As indicated in subsection 2(4) of Rider J, *Wind Forecasting Service Cost Recovery,* the AESO will adjust Rider J charges to reflect variances from the forecasts of cost and energy initially used to determine the values of the rider, and will incorporate the adjustments in the rider in the following year. The cost, energy, and revenue amounts in Rider J have accordingly been updated in the 2016 and 2017 ISO tariff update applications[16].

161 The AESO will continue to update Rider J in annual ISO tariff update applications to ensure that revenue and costs for wind forecasting result in no shortfall or surplus for the following year.

162 Wind forecasting service costs over the period 2010-2016 totaled $2.2 million, while Rider J revenues totaled $2.3 million over the same period. The Rider J charge has remained at $0.05/MWh since April 1, 2016, approved by the Commission in both the 2016 and 2017 ISO tariff update applications.

[16] Decision 21302-D01-2016 and Decision 22093-D02-2017.

7 Terms and conditions

163 The AESO proposes two types of revisions to the terms and conditions of the current ISO tariff: (1) substantive revisions to accommodate new processes and initiatives, and to respond to directions previously issued by the Commission; and (2) administrative revisions, for clarity and to improve consistency with the AESO's other authoritative documents. In particular, Section 7.1 below discusses proposed changes to the terms and conditions that respond to the issues raised by the Commission in its Proceeding 20922 closure letter, dated March 29, 2017 ("Closure Letter").[17]

164 The AESO has revised the numbering of subsections within the sections of the proposed ISO tariff terms and conditions to aid in and simply references to subsections in the tariff. The AESO has inserted the applicable section number in front of every subsection number. For example, a reference to subsection 3.7(4) in the proposed ISO tariff is currently referred to as "subsection 7(4) of section 3 of the ISO tariff, *System Access Service Requests.*" In the proposed ISO tariff, the reference would be "subsection 3.7(4) of the ISO tariff, *System Access Service Requests*."

165 Additionally, in the footer, the AESO has included the section number above the page number to aid in page number references.

166 Notably, the substantive revisions to sections 3 and 4 of the proposed ISO tariff, *System Access Service Requests* and *Classification and Allocation of Connection Projects Costs,* are heavily influenced by Commission findings and guidance in recent decisions regarding the following matters:

- The issues raised in the Closure Letter;
- Sending locational price signals to load and generation;[18]
- Greater emphasis on adequate price signals as compared to certainty of cost classification for connection projects, as between system-related costs and participant-related costs;[19]
- Building system transmission facilities only if there is enough certainty that the project is required;[20]
- Actively using advancement costs as price signals, where applicable;[21]
- Actively using price signals to incent load market participants to delay a requested ISD when increased system transmission facility upgrade costs can be avoided by the delay;[22]
- Ensuring incremental system transmission facility costs related to the advancement of ISDs should be borne by the customer;[23] and
- Providing market participants with incentives to provide information that the AESO can rely on for dynamic planning and the development and timing of system transmission facility upgrades.[24]

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[17] Proceeding 20922, Exhibit 20922-X0023.
[18] Decision 3473-D02-2015 at para 19.
[19] *Ibid* at paras 117-118.
[20] *Ibid* at paras 99 and 241, and Decision 2104-242 at para 469.
[21] Decision 3474-D02-2015 at 159.
[22] *Ibid* at paras 88 and 92.
[23] *Ibid* at para 20.
[24] Ibid at para 243.

167 The substantive revisions proposed by the AESO to address these matters are more fully explained in the discussions that follow in this section 7 and include:

- Introduction of "critical information" for connection projects to create greater incentives for a market participant to provide with the AESO with accurate system access service requests ("SASR") information for a connection project (see Section 7.3.1 of this application below).
- Clarification of the AESO's connection alternative selection process, which requires an assessment of "overall long-term costs" (see Section 7.3.7 below);
- A greater emphasis on achieving enough certainty that connection projects will proceed to energization, such that a market participant will be required to satisfy certain requirements before the AESO would be required to include the connection project in the AESO's forecasts and system transmission planning assessments(the AESO would, however, retain the discretion to include a connection project in its forecast at an earlier point in time, where appropriate);
- Introduction of "avoidable construction costs" to create a price signal to ensure that a market participant is charged for possible system cost reductions if the market participant will not agree to delay their ISD (see Section 7.4.2 below); and
- Revisions to the "advancement costs" provisions to create a price signal for load market participants to accept a reasonable ISD having regard to the timing need for system transmission facility upgrades (see Section 7.4.2 below).

168 Other revisions are proposed to reflect processes applicable to, or that have been developed by, the AESO, including:

- Minor modifications to the wording in Section 4 to accommodate the abbreviated needs approval process established under section 4 of the *Transmission Deficiency Regulation* ("ANAP");
- Revisions to system access service ("SAS") agreements;
- Revisions to accommodate the market participant choice process established under section 5 of the *Transmission Deficiency Regulation*; and
- Revisions to allow distribution direct-connect customers to transact directly with the incumbent TFO rather than indirectly through a DFO.

169 To assist in the review of the proposed changes to the ISO tariff terms and conditions, Table 7-0 below identifies the sections of the current ISO tariff terms and conditions to be changed and the nature of the changes. Additionally, Appendix T to this application provides a comparison of the provisions in the proposed terms and conditions, discussed above, to the corresponding provisions in the current terms and conditions. The proposed changes to the structure, format, and language throughout the proposed ISO tariff mean that a "blackline" comparison of the proposed changes is impractical.

Table 7-0 – Existing ISO tariff terms and conditions Section changes

Existing Terms & Conditions	Proposed Changes	Type of Change
Section 1 – Applicability and Interpretation of ISO Tariff	No change	Minor change
Section 2 – Provision of and Limitations to System Access Service	Combines Sections 2 and 3 – Provision of System Access Service	Substantive
Section 3 – System Access Service Connection Requirements	Combines Sections 2 and 3 – Provision of	Substantive

Existing Terms & Conditions	Proposed Changes	Type of Change
	System Access Service	
Section 4 – System Access Service Requests	Renumbered to be Section 3 – System Access Service Requests	Substantive
Section 5 – Financial Obligations for Connection Projects	Renumbered to be Section 6 – Financial Obligations for Connection Projects	Substantive
Section 6 – Metering	Removed	---
Section 7 – Provision of Information by Market Participants	Removed	Some provisions moved to new Section 2
Section 8 – Construction Contributions for Connection Projects	Renumbered to be Section 4 – Renamed to be - Classification and Allocation of Connection Projects Costs	Substantive
Section 9 – Changes to System Access Service After Energization	Renumbered to be Section 5 – Renamed to be - Changes to System Access Service	Substantive
Section 10 – Generating Unit Owner's Contribution	Renumbered to be Section 7 – Generating Unit Owner's Contribution	Substantive
Section 11 – Ancillary Services	Renumbered to be Section 8 – Ancillary Services	Administrative
Section 12 – Demand Opportunity Service	Renumbered to be Section 9 – Demand Opportunity Service	Administrative
Section 13 – Financial Security, Settlement and Payment Terms	Renumbered to be Section 10 – Renamed to be - Settlement and Payment Terms	Administrative

Existing Terms & Conditions	Proposed Changes	Type of Change
Section 14 – Peak Metered Demand Waivers	Renumbered to be Section 11 – Peak Metered Demand Waivers	Administrative
Section 15 – Miscellaneous	Renumbered to be Section 12 – Miscellaneous	Substantive

7.1 Response to the Proceeding 20922 Closure Letter

170 In Decision 3473-D02-2015 the Commission concluded that there is a need to address "whether and how customer advancement costs can be used to ensure that future system transmission facility upgrades are achieved in both a timely and an economic manner".[25] Following that decision, the Commission issued Bulletin 2015-15,[26] establishing Commission-initiated Proceeding 20922 to address these issues ("Proceeding 20922"). In particular, Bulletin 2015-15 outlined the following matters to be considered in the proceeding:[27]

- System transmission project advancement costs as price signals to market participants;
- The effect of sections 15(1)(e) and (f) of the *Transmission Regulation* on classification of advancement costs;
- AESO discretion and the need to develop clear criteria when applying advancement costs in respect of system transmission projects;
- The materiality threshold for applying advancement cost provisions to system projects;
- Application of advancement cost provisions to non-radial system transmission projects;
- Application of advancement cost provisions to upgrades/enhancements of exiting system transmission facilities;
- Application of system project advancement costs to generators;
- Application of system project advancement costs to distribution utilities;
- Time limitations on participant-related classification of system project advancement;
- The impact of system transmission project advancement cost provisions on transmission system planning and project execution;
- The adequacy of the market participation accountability mechanisms in the ISO tariff; and
- Application of good electric industry practice to staged loads.

171 Subsequently, in the Closure Letter,[28] the Commission advised that, since the release of Bulletin 2015-15, additional evidence had been filed by parties in various Commission proceedings that the Commission considered to have considerable overlap with the issues that were to be addressed in

[25] Decision 3473-D02-2015 at para 99.
[26] Bulletin 2015-15, *Commission-initiated proceeding to address the customer advancement cost component of the Alberta Electric System Operator's tariff* (October 22, 2015).
[27] Decision 3473-D02-2015 at paras 99-247.
[28] Proceeding 20922, Exhibit 20922-X0023.

Proceeding 20922, which led the Commission to conclude that the matters to be addressed in Proceeding 20922 were broader than initially contemplated. Accordingly, the Commission determined that such matters should instead be considered as part of this comprehensive 2018 ISO tariff application and closed Proceeding 20922.[29] As Appendix 1 to the Closure Letter, the Commission attached an issues list to assist the AESO and stakeholders with the development and exploration of issues to be considered in this application. In particular, the Commission raised three issues in response to which the AESO has set out its views below.

7.1.1 Issue 1 - Legislative framework

172 At paragraphs 4 and 5 of Appendix 1 to the Closure Letter, the Commission outlined the first issue regarding the applicable legislative framework as follows (citations omitted):

> *4. Because of the nature of the energy market in Alberta, Alberta's electricity legislation has identified that planning for an <u>uncongested transmission system</u> is a key responsibility that should be allocated to the AESO. For example, sections 15(1)(e) and (f) of the Transmission Regulation provide direction on the <u>allowed degree of congestion</u>, while Section 33 of the Electric Utilities Act establishes the duty of the AESO to forecast the needs of Alberta and to develop plans for the transmission system reflecting the AESO's forecast of such needs, while Section 17 requires the AESO to assess the current and future needs of market participants and plan the transmission system to meet those needs as well as to make arrangements for the expansion of and enhancement to the transmission system. Section 8 of the Transmission Regulation requires the AESO to consider both future load growth and anticipated generation additions for the purposes of developing its transmission system plans.*
>
> *5. One interpretation of sections 15(1)(e) and (f) and Section 8(a) of the Transmission Regulation is that the AESO is required to ensure that it plans and arranges transmission system expansions or upgrades, in a manner that assures <u>that any and all forecast firm load additions can be accommodated by the date requested</u>. However, it is also possible to interpret Section 8 and Section 15 provisions as establishing different targets, one to be met for construction of transmission to serve generation (Section 15 – without constraint) and another to serve forecast load (Section 8 – available in a timely manner). <u>Because these planning restrictions affect the ability of the AESO to set and alter in-service dates, which in turn could affect the cost of achieving its congestion and planning mandates, the Commission is interested in parties exploring whether or not it is possible, desirable or feasible for the AESO to apply the less restrictive interpretation of these provisions.</u>*
>
> [Emphasis added]

173 In considering this issue and having regard to the Closure Letter, the AESO found the following statements of the Commission in Decision 2014-242 to be particularly enlightening and instructive to the interpretation of the legislative provisions that govern how the AESO must plan and arrange development of the transmission system:

> *465. Section 17 of the Electric Utilities Act sets out the duties of the AESO, and includes the following in clauses (i) and (j):*
>
> > *(i) to assess the current and future needs of market participants and plan the capability of the transmission system to meet those needs;*
> >
> > *(j) to make arrangements for the expansion of and enhancement to the transmission system;*
>
> *466. The Commission considers that under clauses (i) and (j) of Section 17, the AESO has a duty to plan and arrange for new transmission facilities, <u>but clauses (i) and (j) of Section 17 do not legislate any specific urgency to complete a transmission system project. Similarly, Section 33(1) of the Electric Utilities Act requires the "timely implementation of required transmission</u>*

[29] *Ibid*, Appendix 1 at para 5.

> *<u>system expansions and enhancements" but leaves it to the AESO to determine what the timely implementation should be.</u>*
>
> *467. As well, the Commission also agrees <u>that Section 15(1)(e) of the Transmission Regulation does not govern when the AESO must accommodate load connections, unless circumstances exist where the forecast load requires enhancements to the existing transmission system to eliminate any anticipated congestion.</u> The Commission considers that when the driver for constructing facilities is the provision of service to a new load customer in an area that does not have existing transmission facilities and the new transmission facilities are to be designated as system-related (by virtue of considerations such as a looped configuration), then there would be no effect on system congestion. In these circumstances, there is no expectation of a potential benefit in the energy market from the relief of congestion.*
>
> *468. Moreover, even in instances where sections 15(1)(e) and (f) of the Transmission Regulation govern, <u>the legislative scheme does not impose a deadline by which the objectives in sections 15(1)(e) and (f) must be achieved</u>. To the contrary, Section 15(2) of the Transmission Regulation provides for exceptions to the requirements set out in Section 15(1). These provisions recognize that it will take time to meet the requirements in Section 15(1) and that the AESO must have some ability to be relieved of its duties under sections 15(1)(e) and (f), on a temporary basis, so it is not in contravention of the legislation. Additionally, Section 15(3) of the Transmission Regulation authorizes the AESO to utilize a non-wires solution on either a permanent or interim basis. Further, Section 16 of the Electric Utilities Act imposes a duty on the AESO to exercise its power and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the transmission system and to promote a fair, efficient and openly competitive market for electricity.*
>
> *469. Having considered the operation of all of these provisions, the Commission finds that the AESO has the responsibility to fairly and economically manage the timing for the construction of an uncongested system while the Commission has the overall authority to provide relief to the AESO in meeting this obligation through the Commission's approval of exceptions pursuant to Section 15(2) of the Transmission Regulation and in the Commission's authority to specify the period of time for which the exceptions would apply. Notably, the AESO has not exercised the discretion granted to it.*
>
> *470. The Commission considers that the exercise of the AESO's discretion in the context of its duty to manage the timing for the construction of an uncongested system safely and economically is relevant to the Commission's assessment of whether, and to what extent, costs related to the advancement of system projects, driven at the request of a market participant, should be designated as participant-related cost and paid for by the requesting market participant.*
>
> *…*
>
> *474. As discussed above, the AESO has a duty to carry out its responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the transmission system and to promote a fair, efficient and openly competitive market for electricity. <u>This includes the discretion to target the completion of system projects in a timeframe that can be completed at a reasonable cost.</u>*
>
> [Emphasis added]

174 The AESO considers that it is possible, desirable and feasible to apply what the Commission has referred to as the "less restrictive interpretation" of the provisions cited by the Commission. In particular, the AESO is of the view that it is not required to accommodate "any and all forecast firm load additions" by the ISD requested by a market participant. Rather, the AESO must accommodate load additions in a timely manner having regard for the safe, reliable and economic operation of the transmission system.

175 The AESO's duties to forecast the current and future needs of Alberta and plan and arrange for new transmission facilities to meet those needs are set out in sections 17(i) and (j) as well as section 33 of

the Act. As noted by the Commission, those sections do not legislate any specific urgency to complete transmission system expansions and enhancements, but require only the timely implementation of such projects as determined by the AESO.

176 Further guidance in respect of the AESO's transmission forecasting and planning obligations is provided in sections 8 and 15 of the *Transmission Regulation*. In particular, section 8(a) provides that the AESO "must anticipate future demand for electricity, generation capacity and appropriate reserves required to meet the forecast load so that transmission facilities can be planned to be available in a timely manner to accommodate the forecast load and new generation capacity." Again, as noted by the Commission, no specific timeframe is prescribed, but the obligation to accommodate forecast load and new generation capacity must be met in a timely manner. Section 15 provides additional criteria that the AESO must adhere to in planning the transmission system. Section 15(1)(a), for example, provides that the AESO must plan a transmission system that satisfies reliability standards. Sections 15(1)(e) and (f), as noted by the Commission in the Closure Letter, "provide direction on the allowed degree of congestion" [emphases added] on the transmission system to be planned by the AESO. Additionally, the *Transmission Regulation* refers to the use of milestones when market participants will be directly affected by critical transmission infrastructure, and the use of load and generation growth as the determining factor of those milestones.[30]

177 To understand the interplay between sections 8 and 15(1)(a), (e) and (f), and how those provisions relate to accommodating new load and supply connections, it is helpful to consider and distinguish between the concepts of "congestion" and "constraints", which the AESO defines, respectively, as follows:

> "**Congestion**" occurs when the transmission system lacks the ability to transmit electricity from in-merit supply to a given electricity consuming area without contravening reliability requirements. In other words, congestion arises as a result of the requirement to limit the flow of electricity on transmission lines (for the purposes of maintaining reliability to below the supply/demand balance determined by the dispatch merit order).[31]
>
> "**Constraint**" refers to: (i) an element of the transmission system that physically limits power flow; (ii) an operational flow limit imposed upon an element or a group of related elements to protect reliability; or (iii) a lack of transmission capacity needed to deliver electricity from existing or potential sources of supply without violating reliability criteria.

178 While congestion results from a constraint not all constraints lead to congestion. Further, as congestion is a term used to describe the inability to dispatch anticipated in-merit electric energy, it predominantly relates to generation and not load.

179 Because of the nature of congestion, when planning for the accommodation of a new demand connection, the AESO is predominantly concerned with meeting the criteria in section 15(1)(a), which requires that the AESO plan a transmission system that satisfies Alberta reliability standards.[32] The

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[30] *Transmission Regulation*, AR 86/2007 at sections 4.1 and 11(4) and (5).

[31] This definition is consistent with that set out in Section 1(1)(b) of the *Fair, Efficient and Open Competition Regulation*, AR 159/2009, which provides that congestion means "a situation where anticipated in-merit electric energy cannot be dispatched due to a constraint affecting the interconnected electric system", as well as the following definition provided by the Commission's predecessor at paragraph 5 of EUB Decision 2002-099, *Transmission Administrator, Congestion Management Principles* (November 5, 2002):

> Congestion occurs when the transmission system cannot accommodate all transactions that would normally occur among customers based on merit order dispatch due to physical or engineering limitations. The physical limitations are determined by the physical capacities of transmission components. The engineering limitations are expressed through the application of accepted reliability and operating criteria.

AESO's connection assessments in support of new demand connections are therefore concerned with identifying a *reliable* demand connection, and not with the potential curtailment of generation. The AESO considers that it is generally required to plan the transmission system and make arrangements for expansions or enhancements consisting of wires solutions (as opposed to non-wires solutions such as Remedial Action Schemes ("RAS") or Transmission Must Run ("TMR") arrangements) to *reliably* connect the market participant. Non-wires solutions for demand connections can only be proposed as planning solutions to the extent permitted under section 15(3) of the *Transmission Regulation.* Unlike in the case of generation (i.e. supply) connections, which may result in congestion or the exacerbation of existing congestion, a reliability issue resulting from a demand connection must be resolved prior to energization, subject to the availability of an exception under section 15(3), to ensure that the criteria in section 15(1)(a) are met.

180 When planning for the accommodation of new generation, on the other hand, the AESO is predominantly concerned with meeting the requirements of section 15(1)(e) regarding congestion. The AESO's connection assessments in support of new supply connections are therefore concerned with identifying existing or anticipated congestion (i.e. the ability of anticipated in-merit energy to be dispatched). Unless the exceptions provided for in sections 15(2) and (3) are justifiable, the AESO plans the transmission system and makes arrangements for expansions or enhancements that enable the connection of generation in a manner that does not give rise to congestion contrary to the criteria set out in section 15(1)(e).

181 Sections 4 and 11 of the *Transmission Regulation* refer to the use of milestones when planning the transmission system. Section 11 authorizes the AESO to specify milestones in needs identification documents ("NID") in order to be reasonably certain when future facilities will be required. The milestones can include the establishment of need based on load growth, generation addition, and commitments by the prospective owners of generating units to construct a unit, the receipt of payment of local interconnection costs, the issue of permits or approvals, and any other indicators of need as may be prescribed by the AESO.[33]

182 In summary, by virtue of the characteristics of demand connections and the AESO's duty under section 15(1)(a) to plan a transmission system that meets Alberta reliability standards, the requirements set out in section 15(1)(e) are generally not engaged when the AESO discharges its duty to forecast demand and plan the transmission system to accommodate new loads. Accordingly, the AESO is of the view that sections 15(1)(e) and (f) should not be interpreted as imposing a requirement that any and all forecast firm load additions must be accommodated by the date requested. Stated otherwise, it is the AESO's view that the requirements established in section 15(1)(e) relate to supply considerations, not demand considerations. Moreover, even in circumstances where the section 15(1)(e) requirements are applicable, they are subject to exceptions that "recognize that it will take time to meet those requirements."[34]

183 In accordance with sections 5, 17(i), 33(1) and 34(1) of the Act and sections 4, 8, 11 and 15 of the *Transmission Regulation*, the AESO considers that it is mandated to plan a transmission system that is flexible, forward-looking and reasonably anticipates new load and generation.[35] While the AESO must reasonably anticipate and respond to forecast load and generation, it must do so not only with a view to the market participant's requested ISD, but also with a view to fairly and economically managing the timing of system transmission facility upgrades,[36,37] targeting the completion of such

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[33] *Transmission Regulation*, AR 86/2007 at section 11.
[34] Decision 2014-242 at para 468.
[35] Decision 2009-126 at paras 150-151.
[36] Decision 2014-242 at para 269.

projects in a timeframe that can be completed at a reasonable cost,[38] and in recognition of the uncertainty associated with forecast load and generation needs.

7.1.2 Issue 2 - Advanced system-related classification of radial transmission projects

184 At paragraphs 6-9 of Appendix 1 to the Closure Letter, the Commission addressed the "in-advance system-related classification in section 8:3(3)(b)"[39] of the tariff, which the Commission noted may result in a connecting market participant having "an incentive to overstate its long-term requirements, since it will not bear the full costs of such a decision", with the result that "the AESO could be incorporating inaccurate forecast information into its long-term plan ("LTP") for required transmission facilities."[40]

185 At paragraph 9 of the Closure Letter, the Commission went on to outline the following issue to be addressed by parties as follows (citations omitted):

> *9. As a result of the incentive effects and cost implications associated with the AESO's tariff classification of system-related costs, the Commission would like parties to address <u>whether Section 8:3(3)(b) from the AESO's tariff should become more restrictive in terms of which transmission projects, if any, should receive in-advance system classification</u>. The Commission also would like parties to <u>address how the current AESO tariff practice of advancement cost designation could be improved to address the balance between the preferences for certainty among one set of market participants and the desire to minimize the cost of transmission development among another set of market participants</u>.*
>
> [Emphasis added]

186 In response to the issue of whether the current subsection 3(3)(b) of section 8, *Construction Contributions for Connection Projects*, should become more restrictive in terms of which transmission projects should receive in-advance system classification and whether the advancement cost provisions should be improved, the AESO is proposing a number of revisions to the current terms and conditions to address these concerns, which are explained in Section 7.4 below.

187 The issue of the AESO incorporating inaccurate information provided by market participants into its forecast and LTP for system transmission facilities is further elaborated below in Section 7.1.3 below.

188 The AESO is of the view that these proposed revisions strike a just and reasonable balance between the preference of some market participants for certainty regarding ISDs and the desire of other market participants to minimize the cost of system transmission facility upgrades.

7.1.3 Issue 3 - Load forecasting

189 Paragraphs 10 – 14 of the Closure Letter relate to this issue. At paragraph 10, the Commission referred to concerns expressed by interveners that "the AESO's forecasts of Alberta Interconnected Electric System ("AIES") energy increases have consistently been in excess of the actual increase in load that has occurred."[41] In paragraphs 11 and 12, the Commission indicated that there is no financial incentive for large industrial customers or individual customers to provide the AESO with accurate or conservative forecast information and that, in fact, providing inaccurate forecast information to the AESO may enable these customers to avoid cost-related consequences. In order to

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[37] System transmission facilities in proposed subsection 4.2(3) as being transmission facilities that are required by the ISO for the benefit of many market participants.
[38] Decision 2014-242 at para 474.
[39] Proceeding 20922, Exhibit 20922-X0023, Appendix 1 at para 8.
[40] *Ibid.*
[41] *Ibid,* Appendix 1 at para 10.

address concerns regarding the use of inaccurate forecast load information for planning transmission system facility upgrade decisions, the Commission requested the following additional evidence:

> *13. The Commission is interested in receiving evidence on how to address these incentive issues. For example, is it advisable to change or enhance the forecast methodology; change the ISO tariff provisions regarding system-related costs, local investment, customer contribution or participant-related costs; or introduce a target rate of load growth?*
>
> *14. If a target could be established, would it then be possible to devise provisions in the ISO tariff that would allow certain market participants who desire load connections more quickly than planned to do so only if there is no net cost to other market participants?*

190 The AESO notes that its system NIDs are based on forecasts of relevant total load and generation within a given study area, and not on a forecast system load energy (previously referred to as AIES energy). Therefore, any potential over or under-forecasting of system load energy growth will not lead to unjustified system transmission facility upgrades. As a result, emphasis on the AESO's forecasts of "AIES energy" in the context of transmission system facility upgrades is not warranted.

191 The AESO undertakes project-specific forecasts or assessments of the underlying drivers of load and generation to ensure that any filed system NIDs contain the most up-to-date information. As the AESO develops its long-term outlook based on broad economic assumptions, it is prudent for the AESO to conduct a more detailed review of a smaller geographic area to ensure that the specific area drivers of load and generation are fully understood before recommending a system transmission facility upgrade. For example, in a recent system NID[42] for a 138-kV transmission system facility upgrade in downtown Calgary, the AESO utilized a load forecast that was less than the AESO's corporate forecast, following the completion of the AESO's detailed area review of specific load drivers in downtown Calgary, along with recent trends of load growth.

192 In addition to consideration of the latest load and generation drivers, the AESO also uses milestones that must be met in order for the system transmission facility upgrades to proceed, rather than the achievement of a targeted ISD, to ensure that system transmission facility upgrades are not constructed before they are needed. For example, in a system NID for a rebuild of transmission line 807L,[43] the AESO established milestones for development which needed to be met prior to commencing construction. This provided greater cost protection for ratepayers related to uncertainty in load growth in the area and the need for the rebuild.

193 Notwithstanding the AESO's existing mechanisms to mitigate the risk of market participants overstating their requirements, the AESO shares the Commission's concerns regarding potential incentives for market participants to provide inaccurate information, which may result in over-building of the transmission system, and the avoidance of cost-related consequences for such market participants. Therefore, the AESO has proposed changes to the terms and conditions in this application to ensure greater contractual and monetary incentives for market participants to provide accurate and timely information to the AESO in order for the AESO to plan and operate the transmission system reliably, while minimizing the cost impact to other market participants. These proposed changes include:

(a) introducing "critical information" in section 3 of the proposed ISO tariff, *System Access Service Requests*, to ensure SASRs are submitted to the AESO in a manner that allows the AESO to be sufficiently confident that a connection project's type (load, generation or both), generation type (if applicable), contract capacity, ISDs and location are accurate throughout

[42] Proceeding 21038, Exhibit 21038-X0006 at page 6,
[43] Proceeding 22040, Exhibit 22040-X0011 at pages 13-14.

the connection process, as well to provide more accurate information to the AESO's long-term forecasting and planning processes. If a market participant requires an amendment to a previously AESO-accepted SASR, the market participant must apply to the AESO to amend the SASR and the AESO may require new studies to be completed by the market participant or request changes to the connection alternative. Following the review of the amendment, the AESO may accept the amendment to the critical information, potentially with an adjustment of the connection project in AESO's connection process or cancel the SASR; and

(b) imposing in the proposed section 3, *System Access Service Requests*, a requirement for the earlier execution of SAS agreements in the connection process. The AESO will only file a connection NID if a SAS agreement has been executed by the market participant. Further, the SAS agreement would automatically become effective following the later of: (i) the issuance by the Commission of permit(s) and licence(s) for the project and (ii) the issuance or resolution of any other applicable regulatory or non-financial matters. For Rate STS customers, the effect of this change is that the generating unit owner's contribution ("GUOC") will have to be paid within 30 days after a SAS agreement becomes effective, as discussed in Section 7.3.9 below, which creates a financial incentive to generators to provide accurate information before the AESO files a NID. For Rate DTS customers, the effect of this change is that after a SAS agreement has been executed and becomes effective, any change to timing and contract capacity will require either a five year notice period, in which case the market participant will pay a Rate DTS bill based on the original requested capacity, or a payment in lieu of notice, in accordance with proposed section 5, *Changes to System Access Service*. This will create a financial incentive for Rate DTS market participants to ensure that requested ISDs and requested contract capacity are certain before a connection NID is submitted to the Commission and included in AESO's forecasting and LTP processes.

194 Past AESO forecasts reflected the current and anticipated trends at the time of development, based on the latest information. The AESO acknowledges that past forecasts of system load energy sometimes over-estimated growth in actual demand. However, the AESO continually reviews its load forecasting methodology, processes, and tools as part of the AESO's goal of continual process improvement.

195 The AESO has adopted a new methodology whereby the load forecast is significantly less reliant on specific market participant information unless there is enough certainty that a specific load project will proceed to energization. This is reflected in the AESO's most recent corporate forecast, the 2017 LTO, which shows a significant reduction of forecast load growth compared to previous forecasts. This is due to the AESO's revised economic growth expectations, energy efficiency assumptions and load forecast modelling adjustments which reduced weight on forecast information provided by market participants and is discussed further below. It is the AESO's opinion that the load growth in the 2017 LTO is a reasonable outlook of future load.

196 In past forecasts, the AESO relied upon a five sector (oilsands, industrial without oilsands, commercial, residential and farm) energy targeting approach to determine macro-level energy growth over the next 20 years. In the 2017 LTO, the AESO instead relied on the Alberta internal load modelling framework currently used in the AESO's mid-term load forecast as an interim process, which is an input into the AESO's *24 Month Supply and Demand Forecast*. This mid-term load forecast has demonstrated better accuracy than the five sector modelling approach and is expected to be more accurate and representative of load growth, especially in the near term.

197 A further forecast process change is the consideration of DFO load forecasts in the AESO's load forecast process. The AESO routinely requests DFO load forecasts by substation because DFOs have information on projects and anticipated load growth beyond the transmission system, which the

AESO does not have. In past AESO load forecasts, the DFO load forecasts were given significant weight. While DFO load forecasts continue to help provide the AESO with information regarding where DFOs forecast load-growth-related development, the AESO is now placing less weight upon DFO load forecasts due to the AESO's review of historical DFO forecast accuracy and an enhanced understanding of DFO load forecast methodologies.

198 In the Closure Letter, the Commission asked whether it would be advisable to establish a target rate of growth. In the proposed subsection 3.4(2)(b)(ii), *System Access Service Requests*, and discussed further below, the AESO is proposing to assess a demand connection project's ability to connect at its requested contract capacity in an area by evaluating the capacity in the area and with the inclusion of five years of forecast area growth. However, there are certain issues associated with using target rates of growth that need to be considered. AESO load forecasts are primarily based upon underlying economic drivers. If economic-driven load forecasts identify a need for system transmission facility upgrades and a new demand connection project applies to connect in the area, such that the need for upgrades is assessed to be required earlier than previously forecast, the AESO cannot reasonably conclude whether the project in question is or is not part of the economic-driven load forecast. This is a challenging issue to address, as where a forecast is provided for an area, it is difficult to determine how much of new load was previously considered or not considered in the forecast. As such, the AESO has included in proposed subsection 3.4(2)(b)(ii) the discretion to assess a connection project by including five years of load growth in the connection studies, in an effort to determine if there is sufficient capacity to accommodate the connection . If the AESO determines there is insufficient capacity given the SASR, the market participant will be offered a reduced contract amount allowing the AESO to reliably plan and operate the transmission system without having to build or enhance system transmission facilities.

199 The AESO is proposing numerous changes to the terms and conditions, including the current advancement cost provisions and the creation of a new avoidable construction costs provision, and other requirements relating to the provision of system access service, as discussed in Section 7.4.2 below which, in the AESO's view, addresses the Commission's concerns and questions.

200 The AESO also considers that the aforementioned load forecast process improvements and transmission over-build risk mitigation measures will further ensure that individual load market participants do not cause undue ratepayer-funded system transmission upgrade costs.

7.2 Section 1 – Applicability and Interpretation of ISO Tariff

201 The AESO is proposing to consolidate three provisions relating to the use of AESO discretion in the current ISO tariff into the following subsection 1.4 of the proposed ISO tariff:

> *1.4 The ISO and a market participant who has requested or is receiving system access service, individually and collectively, must act reasonably in exercising discretion permitted by the ISO tariff.*

202 The AESO considers that the replacement of the provisions listed below with the proposed subsection 1.4 will increase clarity and transparency for market participants:

- subsection 8 of section 2, *Provision of and Limitations to System Access Service*;
- subsection 10 of section 8, *Construction Contributions for Connection Projects*; and
- subsection 6(4) of section 12, *Demand Opportunity Service*.

203 According to proposed subsection 1.3(f) the bolded terms in the ISO tariff are defined in the *Consolidated Authoritative Documents Glossary*. The AESO is requesting the approval of the updated defined terms provided in Appendix U to this application.

7.3 Section 4 – System Access Service Requests

204 The AESO proposes to substantially revise the current section 4 (renumbered as section 3) primarily to:

- provide greater guidance to market participants regarding the requirements to request system access service and how to amend an existing SASR; and
- impose new requirements upon market participants to ensure that they provide the AESO with current and accurate information in connection with a SASR, and that connection project information is updated or amended by the market participant, as necessary, in a timely manner throughout the connection process. The AESO considers that the concept of "critical information" for a SASR will incent market participants to provide accurate information at the beginning of the connection process regarding information that includes, as contract capacity, requested ISDs, location, and, in the case of a DFO, the existence of multiple SASRs in the same geographical area. Additionally, the AESO considers that additional certainty for system transmission projects can be attained by earlier execution of SAS agreements and, if applicable, earlier payment of GUOC and advancement costs (discussed further in Section 7.3.2 below). Finally, the AESO considers that new requirements, to ensure that the AESO's selection of a preferred alternative includes an evaluation of lowest "overall long-term costs",[44] and to ensure that the AESO examines the impact on the transmission system of all viable connection alternatives, to be appropriate and of benefit to all market participants.

205 As the current Section 4 has been substantially revised, the following headings in this part of the application refer to the headings of the revised subsections.

7.3.1 Applying for System Access Service or Change to an Existing System Access Service

206 A market participant seeking new service or altered service must submit a complete SASR. The AESO relies on the information included in a SASR to determine the most appropriate connection process to follow. A SASR is required for each of:

- Load, generation, or dual-use connections or upgrades that may require system transmission facility upgrades;
- Supply connections or upgrades with a net to grid of zero MW;
- Changes to contract capacity or termination of an existing SAS agreement;
- Equipment changes at an existing transmission point of connection;
- Generator connections or upgrades that connect to an electric distribution system that are 5 MW or greater; and
- Generator connections or additions to an electric distribution system that require a new or amended SAS agreement as determined by a DFO.

207 The AESO proposes revisions to the current subsection 2(2) to require market participants to provide, in a SASR, specific information that the AESO refers to as "critical information", about the connection project that the AESO will rely upon to plan the connection. The critical information includes the location of the proposed facility, the capacity (MWs) requested, and the requested in-service-date ("ISD") of the facilities. If critical information changes during the development of the connection project, the connection alternative will generally need to be re-evaluated. If a market participant requests changes to the critical information for a connection project, then under proposed

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[44] Overall long-term costs means all material costs arising from the connection project, evaluated on a life-cycle basis and including costs related to all immediate and future transmission facility upgrades (which may entail both participant-related costs and system-related costs) and distribution facilities, that are affected by the choice of connection alternative and are required to maintain transmission standards and reliability

subsection 3.7(2) there may be effects on the connection studies, on the connection alternative (as it may no longer be valid), the connection project's progress and position in the AESO's connection process and connection queue. In some cases, changes to the critical information may result in the SASR being cancelled by the AESO under proposed subsection 3.7(3).

7.3.2 Distribution system connected generation

Provisions regarding distribution system connected generation

208 The AESO has determined that additional clarity should be provided in regard to the appropriate contract capacity for Rate STS and Rate DTS for DFO at a substation, in light of an increase in distribution-connected generation, and the increasing number of SASRs being received by the AESO from DFOs requesting system access service under Rate STS. The AESO notes that as of May 1, 2018, there are about 1,200 MW of distribution-connected generation projects in the AESO Project List with the size of some of the distribution-connected generation projects approaching 70 MW in size. The impact of these projects is highlighting a number of areas where the current ISO tariff does not have enough clarity, and that historical application of some provisions does not work for large amounts of and large sized distribution-connected generation.

209 Rate STS currently applies to system access service at the point of supply, meaning that electricity flowing onto the transmission system is to be calculated and measured at the demarcation point between the transmission system and the applicable electric distribution system. The AESO considers the distribution feeder energized at 25 kV or less and located within the substation fenced area to be transmission facilities, as defined in the Act. As such, the AESO considers the demarcation point between the transmission system and an electric distribution system to be the point at which the distribution feeder exits the substation.

210 In the AESO's view, there have been inaccurate assessments of contract capacity and metering levels for system access service under Rate DTS and Rate STS at substations due to the totalizing of system access service under Rate DTS and Rate STS at the 138 kV bus level or the high side of the transformer, instead of at the feeder level.

211 Inaccurate contract capacity and metering levels for system access service under Rate DTS and Rate STS impact GUOC payments, DTS billing determinants and substation fraction calculations. Substation fraction calculations are used in determining the allocation of connection costs as either demand or supply related, the appropriate DTS investment levels, and in calculating the monthly POD charge.

212 Therefore, the AESO is providing further clarity regarding how system access service for Rate STS and Rate DTS and metering levels should be calculated and measured, to ensure that: (i) the ISO tariff is applied correctly and consistently; and (ii) there is fair and consistent treatment between transmission and distribution-connected generation. Subsections 3.2(2) and (3), 3.6 and 3.7 addresses the above regarding when SASRs are made, when a SAS agreement is executed, and when a SAS agreement becomes effective, respectively.

Concerns with increasing amount and number of distribution-connected generation on the distribution system

213 Historically, substations serving the distribution system were constructed to serve load and the totalizing of load at the transformer or substation level was appropriate. With the recent increase of distribution-connected generation, and in some cases traditional transmission connected generation looking to connect on the distribution system, there is the potential for a large erosion of the DTS load billing determinants due to totalizing of demand and supply at the DFO POD level. The potential

erosion of DTS billing determinants will ultimately lead to higher DTS rates. Further items of concern are as follows:

(a) There should be consistent and fair treatment between transmission and distribution-connected generation. Generally, whether generation connects to the transmission system or the electric distribution system, the impact on and the benefits received from the transmission system are the same. Similarly, the AESO considers that there should be no economic advantage that can be achieved by a generator that connects to the transmission system versus the electric distribution system, or vice versa. For example, a distribution-connected generator should not receive distribution derived transmission credits (resulting from totalizing Rate DTS and Rate STS), lower GUOC payments, or avoid a transmission RAS by virtue of it being connected to the electric distribution system. Any inconsistent tariff treatment between transmission and distribution-connected generators may lead to "tariff shopping" by generators in some circumstances.

(b) Cross subsidies occur as current DFO practices flow any DTS billing reduction resulting from the totalizing of DTS and STS at the substation level through to the distribution-connected generation. This cross subsidy paid to distribution-connected generation will ultimately have to be paid for by load through deferral accounts or higher rates and also provides subsidies that are not available to transmission connected generation, thereby creating market distortions.

(c) POD transmission facilities and costs, which historically have generally been utilized or incurred for load connections, can now be properly reviewed such that the substation fraction (i.e., substation split between generation and load) at each POD is properly calculated to determine the impact on AESO investment and monthly POD charges.

(d) Contract capacity under Rate STS and Rate DTS, as well as the GUOC (which is based on the contract capacity for system access service under Rate STS), should be reflective of the flow of electric energy onto or out of the transmission system (i.e., these flows are not totalized).

(e) Inaccurate Rate DTS and Rate STS contract and metering levels will result in poor information being available for forecasting and planning purposes. Feeder-level metering and contracting will assist with getting more accurate information.

(f) The clarity the AESO is proposing is only applicable at the substation feeder level where it exits the substation. Beyond this point the totalizing of load and generation on individual feeders could still occur and result in cross subsidies to distribution-connected generation, an erosion of DTS billing determinants and higher DTS rates. While this is beyond the control of the AESO, the AESO believes that all generation should be treated fairly and consistently irrespective of how it is connected. To ensure consistent treatment of all distribution-connected generation to transmission connected generation, the distribution tariffs should be reviewed to ensure consistent treatment.

214 Consistent with some of the AESO's concerns identified above, in December 2017, the Commission issued its final report in response to an inquiry into matters relating to electric distribution system connected generation in Alberta. In its report, the Commission observed that "…because the AESO does not provide a credit to the distribution wire owners for reduced transmission system costs due to [DCGs], the distribution wire owners that provide this credit today must recover the cost of this credit

from all of its distribution customers. This amounts to a cross-subsidy from non-[DCG] customers to [DCG] customers." [45] The Commission's report also noted that DFOs agree that providing a subsidy to DCGs at the expense of load customers is a concern.

Non-applicability to industrial complexes (Dual Use Connections)

215 A dual-use connection is a connection where a market participant is an industrial complex and has both a Rate DTS and a Rate STS SAS agreement. Industrial complexes with combined load and on-site generation must be able to develop their own economic supply of generation to serve their integrated processes in the most economic manner possible therefore industrial complexes will continue to be allowed to totalize DTS and STS irrespective of whether they are connected directly to the transmission system under a waiver granted by the DFO and AESO pursuant to section 101 of the Act, or if they are directly connected as the result of a SASR request submitted by a DFO.

7.3.3 Requirement to package all information relevant to particular geographical area

216 The AESO proposes a new subsection 3.2(4), to incent DFO market participants to provide information to assist the AESO in evaluating a broader geographical area to determine the optimal connection alternative(s) given the connection alternatives and distribution facilities, transmission facilities or combination of both that are required to meet reliability standards. Currently, if a DFO wants to transfer load between PODs, or if a DFO is proposing to serve a broader area of load growth through multiple PODs, the DFO typically submits separate SASRs to the AESO. The DFO is not currently required to identify to the AESO whether multiple SASRs will result in a load transfer, or whether multiple PODs are interrelated and may serve a broader area of load growth; thus putting the onus on the AESO to review, identify, and assemble the related SASRs, in order to understand how to respond to SASRs in a particular area. If the AESO cannot evaluate the entirety of interrelated SASRs, there is a risk that a link between separate SASR requests may be overlooked. A broader understanding of the area requirements is critical to properly select the appropriate connection alternative and system transmission facility upgrades that may be required such that transmission system capability can be efficiently utilized. Therefore, the AESO is proposing that DFOs be required to inform the AESO of any related SASRs and that DFOs be required to provide certain information to the AESO with its SASR made under the proposed subsection 3.2(2). This additional information will assist the AESO in identifying and understanding the implications of the SASRs in the same geographical area and the resulting system transmission facility upgrades that may be required.

7.3.4 Amended Critical Information

217 As the information discussed above in paragraph 207 is critical in determining the ISO's preferred alternative, if the critical information of a SASR change at any point in the connection process, proposed subsection 3.8 will require market participants to amend the SASR critical information on a timely basis. If the AESO subsequently determines that the amended critical information has an impact on the selection of the preferred alternative, the AESO may require revised or new connection studies, and may revise its preferred alternative.

7.3.5 Dual-Use Customers Exception

218 Proposed subsection 3.2(5) is similar to the current subsection 2(2). However, the AESO proposes the addition of an exception for dual-use connections to allow a single SASR to be filed in circumstances where a market participant applies for new, or changes to an existing, system access service, where both generation and load exists at a market participant's site.

[45] *Alberta Electric Distribution System-Connected Generation Inquiry Final Report*, December 29, 2017, at para 277.

7.3.6 Review of System Access Service Request

219 The current subsections 3(2) through (4) are similar to the corresponding provisions in the proposed section 3.3.

7.3.7 ISO Preferred Alternative

220 Proposed subsection 3.4(1) describes the types of alternatives the AESO must assess and how the AESO must select its preferred alternative. These provisions are intended to ensure that the market participant clearly understands that their connections may have an impact on the transmission system and that these impacts need to be assessed when considering a connection alternative.

221 According to the proposed revised terms and conditions, if a connection alternative requires a system transmission facility upgrade to satisfy a reliability or operational measure (i.e., constraints or congestion as determined by the AESO), then the alternative must be compared against other connection alternatives that do not give rise to any transmission constraints or congestion, as described in proposed subsection 3.4(1)(b) and (c). The AESO must then choose its preferred alternative for a connection project having regard to the lowest "overall long-term cost" and any impact on the transmission system.

222 Under proposed subsection 3.4(1), the term "overall long-term cost" means all material costs arising from the connection project, evaluated on a life-cycle basis and including costs related to all immediate and future transmission facilities (which may entail both participant-related costs and system-related costs) and distribution facilities, that are affected by the choice of connection alternative and are required to satisfy reliability requirements. As applicable, overall long-term cost should also take into account all relevant current and projected efficiency, timing, land use, safety, environmental, and other applicable considerations. These matters are expected to be addressed by the TFO in the TFO's proposals and estimates.

223 Proposed subsection 3.4(1)(a) identifies various factors to be considered by the AESO when evaluating the overall long-term costs of a connection alternative.

224 Proposed subsection 3.4(1)(b) and (c) provide an indication to the market participant of the types of constraints that the AESO takes into account when evaluating connection alternatives. If a connection alternative is anticipated to result in a constraint on the transmission system, the connection alternative must include an assessment of the system facilities, if any, that will be needed to relieve the constraint. Subsection 3.4(1)(b) and (c) require the AESO to consider Category A conditions (in the case of supply connections), and Category A and Category B conditions (in the case of demand connections) to assess whether a connection alternative will result in or exacerbate constraints on the transmission system. As defined in Alberta reliability standards, Category A (N-0) conditions are conditions in which all transmission facilities are in service (no contingencies), while Category B (N-1) conditions involve the loss of a single system element.

<u>Constrained demand connections</u>

225 Upon review of a demand connection SASR, if the lowest overall long-term cost alternative would result in a reliability issue that needs to be addressed through system transmission facility upgrades, then the market participant requesting system access will have a number of options to manage its connection. In the AESO's view, providing choices to the market participant satisfies the AESO's obligation to provide system access service in a manner that gives market participants a reasonable opportunity to exchange electric energy. The options available to the market participant are as follows:

(a) Pay advancement costs for system transmission upgrades (more fully described below in Section 7.4.2):

If a system NID has not been filed for system transmission facility upgrades, then upon payment of the advancement costs, the AESO would proceed with preparing a connection NID for facilities required to connect the load market participant and system transmission facility upgrades with the allocation of participant-related costs and system-related costs. This process will allow for the coordination of ISDs for the connection project and system transmission facility upgrades. The full payment of the advancement costs would be required before execution of the demand connection's contract execution;

(b) Accept a connection proposal and reduced contract capacity, without constraint for the next five years, that can accommodate forecast area load growth:

Where there is a system transmission capacity limit, the market participant would be required to reduce the originally requested contract capacity to address the area capacity limits. The reduction would also consider five years of forecast area growth, or other amount of reduced contract capacity or period of time that allows the AESO to meet transmission system planning obligations and reliably operate the transmission system. This will ensure that the market participant's connection would not immediately trigger a system transmission facility upgrade upon energization and allow time for the AESO to forecast and plan as well as safely, reliably and economically operate the transmission system ; or

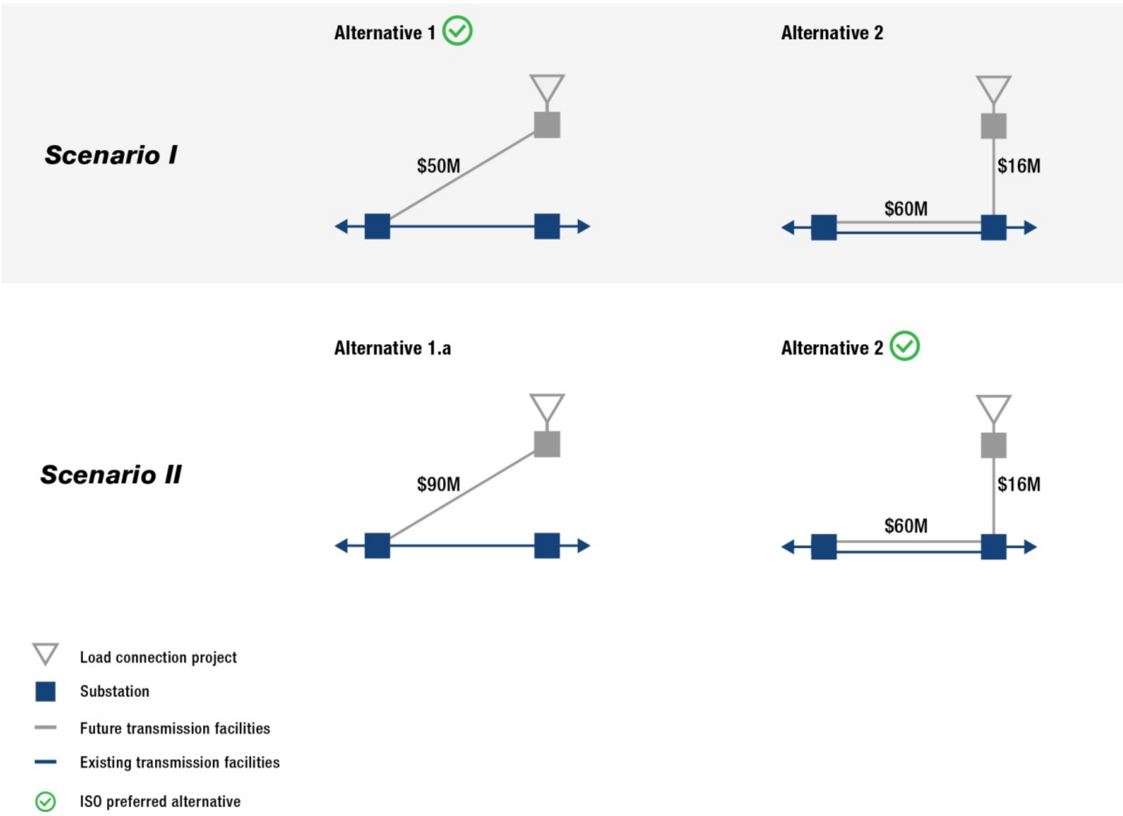
(c) Execute the SAS agreement five years prior to the market participant's projected ISD, including the documented ISD, location and capacity (MW):

In general, a five-year notice requirement would typically provide sufficient time to enable the AESO to plan system transmission upgrades, however, the AESO may need to impose a RAS or other operational measures on the market participant to address reliability issues that are dependent on the timing of the system transmission facility upgrade.

226 The following example will be used to compare the potential alternatives:

Example: Assume a connecting market participant requests 40 MW of DTS service, and the AESO determines two potential alternatives.

Figure 7-1 – ISO preferred alternative selection for demand connection example



227 In Scenario I represented above, based on the preferred alternative selection model, the AESO's preferred alternative for the connection project would be alternative 1 as the lowest overall long-term cost, comprising a radial line ($50 million) to provide an unconstrained connection solution. Alternative 1 has lower overall long term costs than the unconstrained connection solution that includes a system transmission facility upgrade to remove constraints, where Alternative 2 is $76 million.

228 In Scenario II above, based on the preferred alternative selection model, the AESO's preferred alternative for the load connection project would be Alternative 2 as the lowest overall long-term cost, comprising a radial line ($16 million) and a transmission system line upgrade ($60 million) to provide an unconstrained connection solution. Alternative 2 is less than the unconstrained connection solution with no system transmission facility upgrade illustrated in Alternative 1.a ($90 million). Advancement costs (discussed further in Section 7.4.2 below) would apply in Scenario II.

229 In circumstances where the AESO has proposed a permanent non-wires solution in accordance with section 15(3)(a) of the *Transmission Regulation* instead of system transmission facility upgrades to address constraints caused by a connection project and the connecting market participant does not wish to operate under a permanent non-wires solution, the market participant would be required to pay 100% of the costs of the system transmission facility upgrades as part of its connection project.

Congested supply connections

230 The costs of radial facilities required to connect supply will be classified as "participant-related", however, the costs of any system transmission facility upgrades that are advanced cannot be charged to the generator market participant.

231 For a requested supply connection, if the alternative with the lowest overall cost will result in or exacerbate congestion that does not meet the requirements of section 15(1)(e) of the *Transmission Regulation* and a system transmission facility upgrade will be required, then the generator market participant requesting system access can choose one of the following:

(a) accept a connection proposal that aligns with the existing capability of the transmission system by relocating or downsizing the capacity of the facility to be connected;

(b) if acceptable to the AESO, and subject to an exception under sections 15(2) or 15(3)(b) of the *Transmission Regulation*, connect in a manner that results in congestion for a temporary period of time, until a transmission system plan to address the congestion has been developed and implemented; or

(c) if acceptable to the AESO, and permitted under section 15(3)(a) of the *Transmission Regulation*, accept a connection proposal that is subject to a permanent non-wires solution. Consistent with the section 15(1)(e) requirements, if congestion following a contingency event is anticipated to occur less than 5% of the time (calculated on an annual basis), then a permanent RAS would be put in place for a requested supply connection.

232 If the AESO identifies a constraint on the demand aspect of the connection, then proposed subsection 3.4(2) will apply. Where the AESO identifies that congestion exists or will result as a result of the supply aspect of the connection, then proposed subsection 3.4(3) will apply.

7.3.8 Construction Commitment Agreement and Waiver

233 The AESO proposes to move and revise the current subsection 2(8) of section 5 to become the proposed subsection 3.5. The AESO is also proposing to exempt an affiliated TFO and DFO from this requirement.

7.3.9 Execution of Agreement for System Access Service

234 The AESO proposes to require, in the proposed subsection 3.6(1), that a market participant execute a SAS agreement:

(a) prior to the AESO submitting a connection NID to the Commission for approval or, before the AESO approves a connection project under the ANAP, with the agreement becoming effective immediately following the satisfaction of all conditions precedent provided for in the agreement, which will include issuance by the Commission of permit(s) and licence(s) for the connection project and may include the issuance of other regulatory approvals and the resolution of non-financial matters; or

(b) if the construction of transmission facilities is not required for a connection project, within 30 days of the issuance of a letter by the AESO acknowledging completion of an engineering connection assessment for the project and the agreement will become effective upon execution.

235 The earlier execution of a SAS agreement by market participants under proposed subsection 3.6(1) will provide the AESO with increased confidence that a connection project will proceed because financial obligations of a market participant, discussed below, will be triggered following the

satisfaction of conditions precedent when the construction of transmission facilities is required and following the execution of a SAS agreement when the construction of transmission facilities is not required. This will reduce incentives for market participants to overestimate their contract capacity requirements.

236 In particular, the execution of SAS agreements prior to NID filing will aid the AESO in reducing the possibility that system transmission facilities are built for connection projects that do not materialize.

Projects that require the construction of transmission facilities

237 In consultation with stakeholders after the original filing of the 2018 ISO tariff application, the AESO was made aware of concerns that projects may need to be cancelled following Commission issuance of permit(s) and licence(s) when events arise that are not in the control of the connecting market participant. The AESO has re-analyzed the contract execution requirements proposed in the originally filed 2018 ISO tariff application and proposes the following contract execution requirements.

238 Upon receipt of a SASR, the AESO will determine whether providing the requested system access service will require the construction of transmission facilities. Upon this determination, the AESO will complete studies and determine the preferred connection alternative.

239 As noted above, the market participant will be required to execute a SAS agreement for Rate DTS or Rate STS prior to the filing of the connection project NID, or prior to the AESO approving the project under the ANAP.

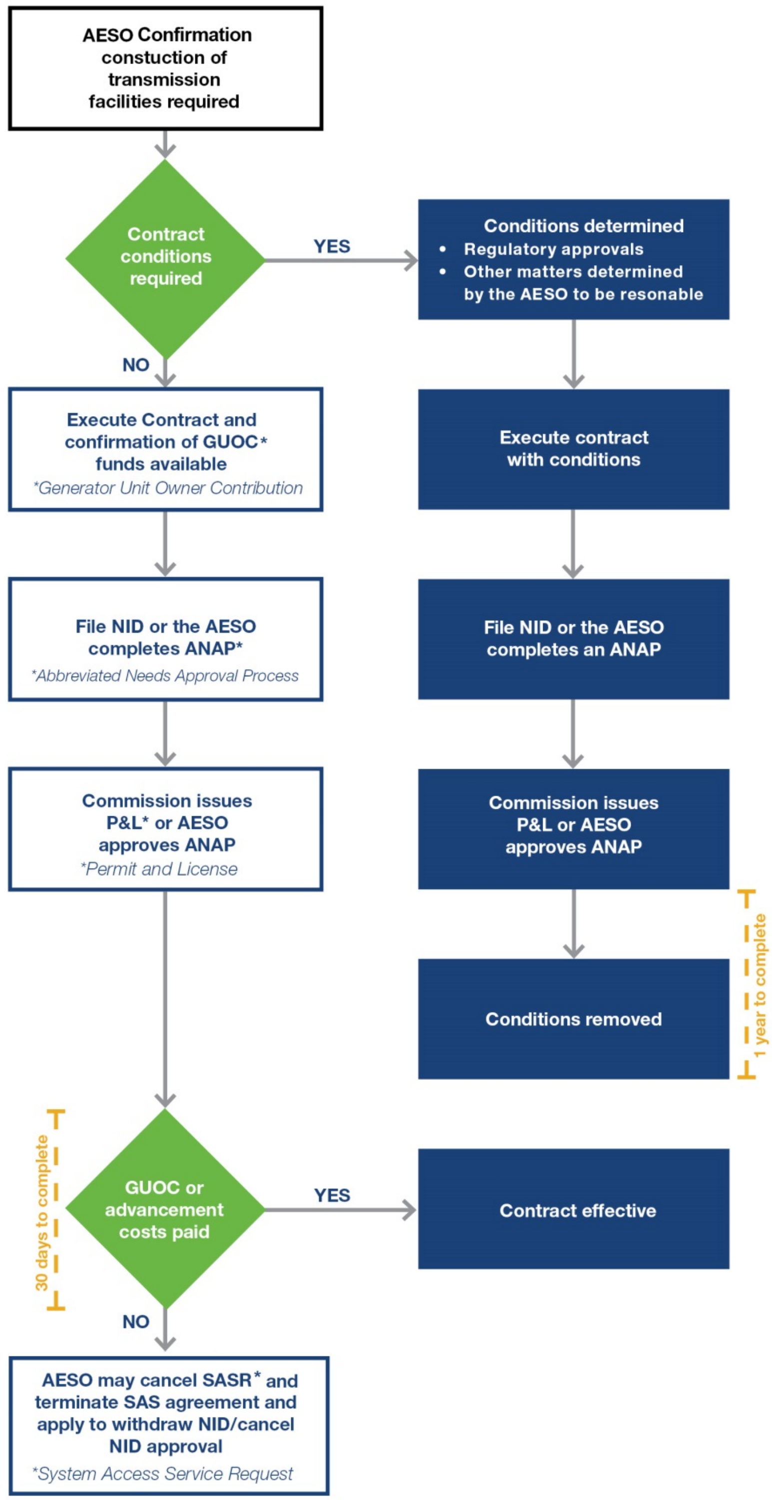
240 A supply market participant will be issued a GUOC invoice at the time of or just prior to the execution of a SAS agreement. A supply market participant will also be required to provide the AESO with satisfactory evidence that the market participant has sufficient funds available to pay the GUOC when due, which will be 30 days after the agreement becomes effective.

241 The AESO considers that some uncertainty can exist for some connection projects where certain regulatory approvals are required or non-financial matters must be resolved before the project can proceed, and these regulatory approvals and matters are largely not in the control of a market participant. In these circumstances, the AESO considers that including conditions precedent in the executed SAS agreement will protect the market participant in the event the project will not go ahead. If a SAS agreement does not become effective within 1 year of the Commission issuing permit(s) and licence(s) because other conditions precedent have not been satisfied, the AESO may cancel the SASR project and the market participant will have no obligation to pay any GUOC or advancement costs determined for a load project.

242 Following a SAS agreement becoming effective, load market participants will be committed to their capacity request, as any reduction or termination of capacity will result in the market participant having to either (i) pay the associated Rate DTS bill based on the originally requested contract capacity for five years; or (ii) make a payment in lieu of notice (also known as “PILON”), in accordance with proposed subsection 5.3.

243 Following a SAS agreement becoming effective, supply market participants will be committed to their capacity request, as any reduction or termination of capacity will result in the market participant forfeiting a portion or all of the applicable GUOC payment.

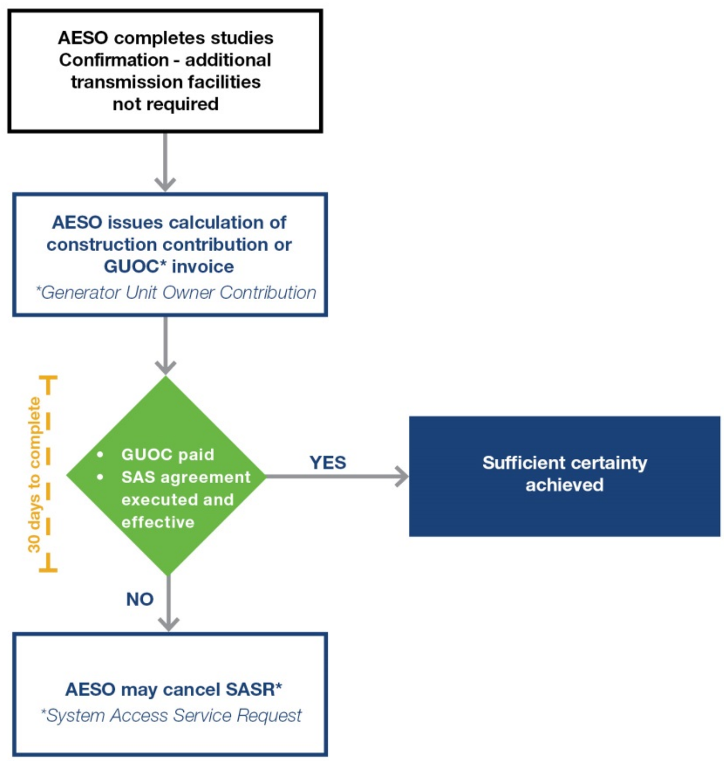
Connection Projects that require construction of transmission facilities



Projects that do not require the construction of transmission facilities

244 The AESO proposes that a market participant will be required to execute a SAS agreements for contract additions, contract increases, and projects where no transmission facilities are required within 30 days of the issuance of a letter by the AESO acknowledging completion of an engineering connection assessment for the project confirming that no changes to the transmission system are required. For a generator, any GUOC payment must be paid within 30 days of executing the SAS agreement.

Connection Projects that do not require construction of transmission facilities



Inclusion of connection projects in the AESO's forecasting and planning processes

245 Under proposed subsection 3.7(6), the AESO must include the critical information of a connection project in the AESO's forecasting and transmission system plan when a SAS agreement becomes effective.

246 Inclusion of a project in the AESO's forecasting and transmission planning processes is significant for connection projects that, by way of their proposed connection, will result in or exacerbate constraints.

247 Subject to Commission approval of the proposed terms and conditions, the AESO intends to apply the provisions regarding critical information, as well as proposed subsection 3.6(1) through (4), not

only to new connection projects, but also to current connection projects that, as a result of a change in critical information, require new study work, a NID amendment, or reassessment under the ANAP.

7.3.10 Amending a System Access Service Request

248 The AESO proposes to add subsection 3.8 to encourage market participants to provide accurate information in their initial SASR, to obligate them to provide new information in a timely manner, and to create accountability in relation to proposed projects that do not proceed.

7.3.11 Alternative Processes

249 Proposed subsection 3.9 is similar to the current subsection 8. The AESO proposes to revise the wording to clarify that the market participant's agreement is not required for the AESO to utilize processes other than those described in proposed section 3.

7.4 Section 8 – Construction Contributions for Connection Projects

250 The AESO proposes substantive revisions to the current section 8, renumbered as section 4 and renamed as *Classification and Allocation of Connection Projects Costs*. As directed by the Commission in Decision 3473-D02-2015,[46] the AESO proposes that supply and demand connections, will be treated differently regarding system transmission facility upgrade costs that should be borne by a market participant in certain circumstances. In particular, advancement costs and avoidable construction costs are only attributable to load market participants. For a dual-use connection, advancement costs and avoidable construction costs will be attributable when AESO studies reveal it is the demand characteristics of a dual-use connection that trigger system transmission constraints.

7.4.1 Connection Costs

251 The AESO is proposing to delete the provisions describing connection costs. The AESO considers that these provisions add little value and dilute clarity around how the costs of connection projects are determined.

7.4.2 Classification of Participant–Related and System-Related Costs

252 The AESO is proposing a number of changes to how it classifies participant and system-related costs.

(i) Participant-related costs

253 The AESO proposes to remove the terms "contiguous" and "non-contiguous" respectively from the current subsection 3(2) of section 8 of the ISO tariff.

254 The word "contiguous" implies that only the cost of facilities that form part of a connection project or that are facilities adjacent to or adjoining the connection project would be participant-related costs. However, the AESO notes that current subsections 3(2) (f) and (j) refer to telecommunications and remedial action schemes, which are connection project components that may be upstream or downstream of the radial connection. Further, there may be instances where other non-contiguous facilities are required only for the sole benefit of a connecting market participant. The wording of the current subsection has caused confusion as some market participants have considered that the cost of such non-contiguous facilities should be classified as system-related costs.

255 Regarding current subsections 3(2) (e) and (f), the AESO proposes changes to the wording of costs associated with telecommunications. In Decision 3473-D02-2015, the Commission held that "local interconnection costs applied to generators for the purposes of Section 28 of the Transmission

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[46] Decision 3473-D02-2015 at para 191.

Regulation will be restricted to the cost of radial transmission facilities required to connect generating units to the transmission system".[47] The AESO is of the view that communications equipment and enhancements are unique, and potentially an exception to this finding, in that they are not necessarily reliant on wires. Rather, communications equipment and enhancements are often built at substations up or downstream of a connection, only for the benefit of the connecting market participant. Accordingly, the AESO proposes that costs for communications equipment and enhancements required for a connection project, if solely required or used by the connecting market participant, be classified as participant-related. If jointly used, then the costs would be shared with other market participants, and if required for system purposes or jointly used for system purposes, then the costs would be classified as system-related costs.

256 The AESO proposes to broaden the current subsection 3(2)(n), which currently refers to "other facilities required to complete the market participant's connection…" to include future facilities. The AESO considers that if the ISO preferred connection alternative could impact planned or future system transmission facilities, or make use of existing system transmission that are planned to change in the near future, that the costs of these impacts should be participant related. In this way, the AESO may deem the costs of future facilities as participant-related costs if the AESO sees that this connection alternative may have an impact on increasing the costs of a planned or future transmission system development.

257 Additionally, the AESO notes that while the market participant may pay a contribution for the AESO's preferred alternative, this does not limit the AESO from seeking approval of a broader system plan for the area that may not necessarily include the exact specifics contained in the preferred alternative, but still provides the same level of service. For the purposes of calculating a construction contribution, the AESO preferred alternative would represent the participant-related costs for a connection project, regardless of the fact that the AESO determined the TFO should construct a different configuration in an effort to optimize existing system transmission facilities.

258 Under proposed subsection 4.2, the AESO proposes to make changes to advancement costs and to introduce avoidable construction costs. Both of these costs can only be applied to demand connections.

(ii) Advancement costs

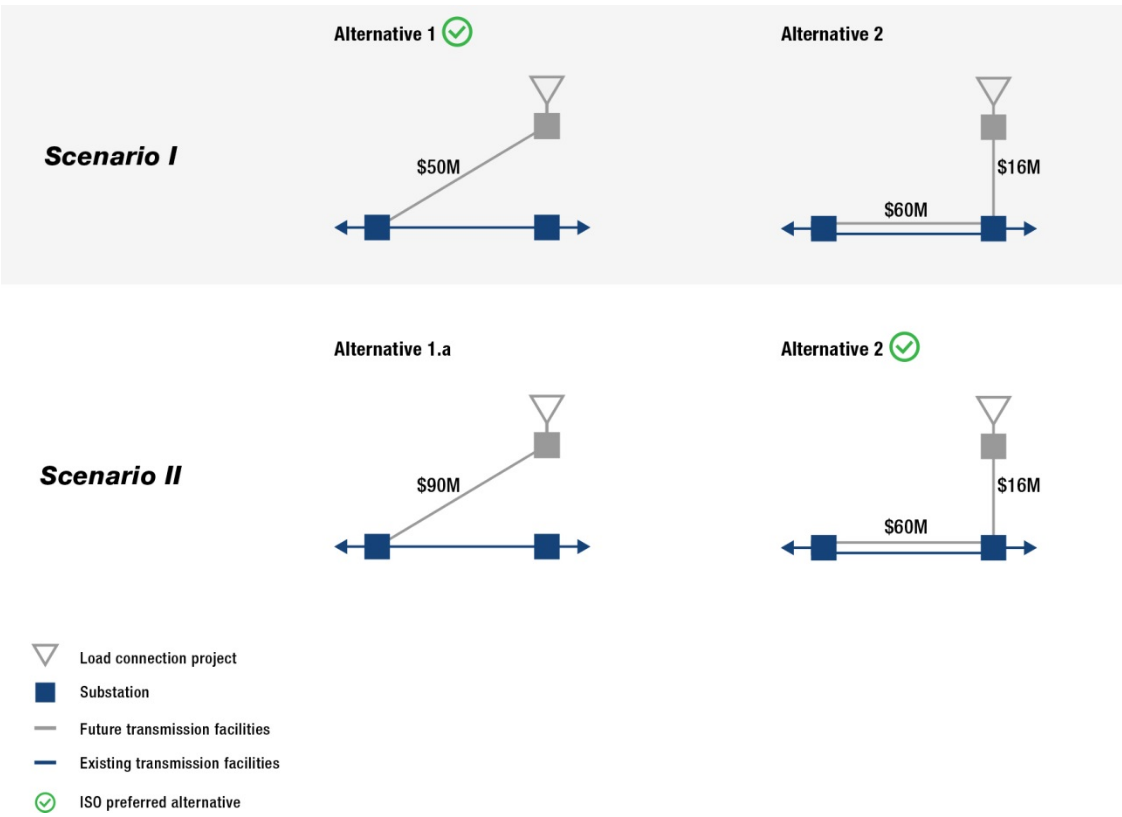
259 The AESO considered a number of approaches, for the purpose of sending a relevant price signal to load market participants, to provide the AESO with greater certainty that a connection project will proceed, and to enable the timely and economic development of the transmission system.

260 As set out in the proposed subsection 3.4(2)(a), the AESO proposes that, for a demand connection project with a system-related cost component, a market participant must pay advancement costs, prior to the AESO filing the connection NID and advancing the system transmission facility upgrade. This preferred approach and potential options available to load market participants are discussed in section 7.3.7 above.

[47] Decision 3473-D02-2015 at para 190.

261 The example described in section 7.3.7 above is duplicated below to illustrate the applicability and calculation of advancement costs options. This is a load market participant requesting 40 MW of DTS contract capacity and the alternative costs are as described in Scenario II:

Figure 8-1 – Applicability of advancement costs



a) <u>Advancement costs calculated under the current ISO tariff</u>

262 The AESO's preferred approach is to maintain the current advancement cost calculation, with some revisions to the calculation and to update the system-related cost provisions. In the AESO's view, the current advancement cost provisions provide a strong locational price signal, and are understood by market participants.

263 This price signal should apply in any case where the AESO's preferred alternative to address a load market participant's SASR requires the advancement of the construction of system transmission facilities to relieve constraints, and not solely when facilities are planned to become non-radial within five years. The AESO considers that "advancement" occurs both when there <u>is</u> a plan in place to address future congestion or constraints, or where future facilities <u>have never</u> been contemplated to address a forecasted area constraint. Consequently, the AESO proposes that advancement costs apply to all demand connections that trigger the requirement for system transmission facilities to be built to accommodate a demand connection.

264 The AESO proposes to revise the existing advancement cost provisions to reflect that advancement costs are calculated based on a five-year advancement of the system transmission facilities, where future system transmission facilities have never been contemplated. The AESO has historically considered that a five-year planning window is required to allow the AESO to plan the AIES in the near-term. This calculation is simple and can be similarly applied for all market participants. In

addition, the advancement costs will reflect a portion the true costs of the system transmission upgrade costs.

265 For example, in the Scenario II provided above in Figure 8-1, based on the alternative selection model, the AESO's preferred alternative for the load connection project would be Alternative 2 as the lowest overall long-term cost, comprising a radial line, estimated at $16 million today, and a transmission system line upgrade estimated at $60 million today, to provide an unconstrained connection solution. Alternative 2 has lower over-all long term costs than the unconstrained connection solution, which does not contemplate a system transmission facility upgrade, illustrated in Alternative 1.a, estimated at $90 million.

266 If the market participant chooses not to reduce capacity to allow the connection project to connect unconstrained, then that market participant will be responsible for the advancement of the system transmission facility upgrades, valued at $60 million. The future value of $60 million for five years, using the AESO discount rate of 6.05% (as posted on July 1, 2017), is approximately $80.5 million. The market participant would be responsible for paying the difference between the current and future amounts, which is $20.5 million in advancement costs.

Advancement costs = [present value capital costs x (1 + discount rate)$^{5\ years}$] – present value capital costs

267 As a result, the participant-related costs would be $36.5 million ($16 million + $20.5 million). The $60 million upgrade would be classified as system-related costs. The advancement costs are considered to be participant-related costs.

268 Proposed subsection 4.2(3)(iii) supports a calculation that will consider the number of months advanced, where the system transmission facilities are included in an approved NID and have a scheduled in-service date that can be advanced as determined by the AESO.

269 Using the example above, the $60 million represents the value of the system transmission facilities identified in the approved NID for the system transmission facilities. The advancement cost calculation in this example would be the present value of the future facilities, using the number of months that the in-service date of the system transmission facilities is advanced.

Advancement costs = [future value capital costs x (1 ÷ (1 + discount rate)$^{x\ months}$)] – present value capital costs

b) <u>Advancement costs calculated on $/MW capacity request</u>

270 Another option is to calculate advancement costs based on a $/MW capacity request. That is, charging a $/MW charge based on a market participant's capacity request.

271 Using the example presented above, if the AESO applied a $/MW DTS capacity charge of $100,000/MW (amount selected for illustrative purposes), the advancement cost charge using this option would be $4 million (40 MW X $100,000/MW). The market participant would be responsible for paying an advancement cost charge of ($16 million + $4 million) $20 million.

272 The $/MW charge would not correlate to the actual cost of the transmission system facilities and, therefore, does not align with the cost causation regulatory principle. For example, the cost of the transmission system facilities could be $2 million, or it could be $100 million. The market participant would receive a weak price signal relating to the actual cost impact of the transmission facilities required to remove the constraint or congestion.

c) Refundable charge based on full cost of system build

273 Another option is a refundable mechanism under which the full costs of a transmission system upgrade ($60 million in alternative 2 above) would be paid by the market participant, and then would be refunded to the market participant upon energization of the facilities.

274 The AESO considers the additional costs associated with this approach to be the “carrying costs” of the $60 million. The designated TFO would hold the $60 million contribution until the connection facilities were energized. The price signal to the market participant would be the costs of financing the $60 million that is being held by the TFO, and possibly any loss of opportunity on that amount. This amount would be less if the $60 million were provided in the form of a line of credit.

275 In the example above, if the market participant failed to energize, the $60 million would be forfeited.

276 The AESO considers that this mechanism provides a locational price signal in alignment with others proposed in this application. However, the AESO considers its preferred approach, as proposed in this application, to provide a stronger locational price signal for market participants, and to more accurately reflect the principle of cost causation.

d) Other refundable charge considerations

277 The AESO also considered a refundable charge based on $/MW and a refundable charge based on the above advancement cost calculation. Under a $/MW charge, the AESO would calculate the refundable charge based on the capacity request made by the market participant and a designated dollar amount. For example, if a market participant requests a 10 MW connection, their refundable charge would be 10 MW multiplied by the $/MW charge as illustrated in paragraph 259 above.

278 The AESO also considers that a refundable advancement cost charge would also dilute the cost causation principle where the non-refundable would offer the additional price signal to the market participant wishing to connect.

(iii) Avoidable construction costs

279 Subsection 3(2)(l) of section 8 of the current terms and conditions define how advancement costs are calculated:

> *(l) the advancement of **transmission facilities** included as part of a critical transmission development or regional **transmission system** project under subsection 3(3)(b) below, calculated as the difference between the present values of the capital costs of the advanced and the as-planned facilities using the discount rate provided in subsection 11 below;*

Subsection 3(3)(b) identifies under which circumstances advancement costs apply:

> *(b) radial **transmission facilities** which, within five (5) years of **commercial operation**, are planned to become looped as part of a critical transmission development or regional **transmission system** project:*
>
> *(i)in the **ISO**’s most recent long-term **transmission system** plan;*
>
> *(ii) in a needs identification document filed with the Commission; or*
>
> *(iii) as the **ISO** reasonably expects will be required in the future;*

280 The current ISO tariff only contemplates that advancement costs apply to those facilities that are planned to be looped within five years of commercial operation, and are calculated based on the costs of a planned system transmission project.

281 In Decision 3473-D02-2015, the Commission determined that the incremental costs of system transmission facility upgrades targeted for completion by a specified ISD in order to serve a specific load market participant should be borne by that load market participant.[48] Having regard to the direction and guidance provided by the Commission in that decision, the AESO now differentiates those incremental system transmission facility upgrades costs from the advancement costs provided for in the current ISO tariff. Notably, the Commission stated its expectation in Decision 3473-D02-2015 that target ISDs should be shifted to a later date if it is possible to avoid incremental costs associated with a target ISD:

> *"162. The underlined passages in paragraphs 476 and 477 of Decision 2014-242 were intended to convey the Commission's expectation that the in-service date should be considered a reasonable target and should shift to a later date if it is clear that a move to a later target date would make it possible to avoid costs expected to be incurred if the target date was not moved. The advancement costs should be measured against the reasonable target date, and not just a previously agreed upon target."*

282 Accordingly, the AESO considers it to be more accurate to refer to such incremental costs as "avoidable construction costs", which are distinct from advancement costs. The AESO is proposing a new provision, subsection 4.2(3)(b), to allow it to delay the in-service date of a system project under construction if there is no system impact. The AESO refers to any savings realized by way of the delay as avoidable construction costs.

283 The AESO recognizes that such a delay can adversely affect the provision of new service or changes to existing service to load market participants. Therefore, the AESO considers that a load market participant should be given the opportunity to mitigate any such impact by electing to pay avoidable construction costs in order to keep all other ratepayers whole in return for maintaining a target in-service date.

284 As a hypothetical simplified example, the AESO notes that a system project under construction costing $100 million that could be delayed by a year to save $5 million of construction costs may have a number of other rate payer costs and benefits that may need to be considered in calculating avoidable construction costs: namely:

(a) additional TFO revenue requirement for $100 million of capital for a year;

(b) $5 million of capitalized avoidable construction costs; and

(c) additional bulk charge and regional charge revenue from the market participant for a year.

285 The AESO notes that items (a) and (c) are revenue requirement and revenue, respectively, while item (b) is a capital cost. The load market participant can elect to pay item (b) upfront and directly to the TFO as an avoidable construction cost thereby fully offsetting the avoidable construction cost. The AESO would accordingly record items (a) and (c) as offsets to the wires portion of its revenue requirement in the production year they are realized. The AESO would include items (a) and (c) on a

[48] Decision 3473-D02-2015 at para 20.

market participants’ corresponding monthly statement of account for system access service. The AESO would determine items (a) through (c).

286 The AESO understands that costs and benefits will vary from project to project and will need to be based on project specifics. The basic principle would be that rate payers bear no responsibility for any additional costs that could occur if the load market participant chooses to maintain an in-service –date if the additional costs could be avoided by delay. If the AESO identifies costs that might be avoided if targeted ISDs are delayed, the avoidable construction costs will be presented to the load market participant. If the market participant pays the avoidable construction costs in addition to the connection costs, the project will proceed as planned. However if the load market participant does not pay the avoidable construction costs, the ISDs of both the connection project and any system transmission facilities required for the connection project may be rescheduled to a later date to avoid the additional costs.

(iv) System-related costs

287 The AESO is proposing substantive changes to the provisions that describe system-related costs. Revisions to the current provisions are proposed to reflect alignment with the proposed subsections 4.2(2) and (3). The AESO considers that there is sufficient detail in the proposed subsections 4.2(2) and (3) to ensure appropriate facilities are designated as participant-related. The general principle of cost causation is being considered, such that if a market participant connection causes additions or upgrades that are only required for that connection and do not provide any benefit to other market participants, those costs should be attributed to that market participant receiving the benefit as participant-related costs.

288 Further, the AESO proposes the removal of any reference to “contiguous” and “non contiguous” as set out in current subsection 3(3) of section 8 as this should no longer be applicable to differentiating between participant-related or system-related costs. As noted above, these terms have caused confusion for market participants, as facilities may be required of a market participant’s connection that are of sole benefit to that market participant, but were “non contiguous” in a strict sense.

289 The AESO also proposes to remove current subsection 3(3)(a) and (b) of section 8, reproduced below:

> ***(3)*** *System-related costs will be those costs related to a connection project including non contiguous components of the project and any costs associated with:*
>
> > *(a) looped* ***transmission facilities****, which are facilities that increase the number of electrical paths between any two (2) substations, excluding the substation serving the* ***market participant*** *and which exclude any new radial transmission line;*
> >
> > *(b) radial* ***transmission facilities*** *which, within five (5) years of* ***commercial operation****, are planned to become looped as part of a critical transmission development or regional* ***transmission system*** *project:*
> >
> > > *(i) in the* ***ISO****’s most recent long-term* ***transmission system*** *plan;*
> > >
> > > *(ii) in a needs identification document filed with the Commission; or*
> > >
> > > *(iii) as the* ***ISO*** *reasonably expects will be required in the future;*

290 The AESO is proposing to remove references to looped transmission facilities as part of this application. A market participant’s connection project will include facilities, as discussed above, that are non-contiguous to the connecting substation, but are only required for the market participant’s

connection. Under the current tariff, communications enhancements that are required for a particular market participant's connection can be installed in several substations and, as such, would be considered "looped" facilities. The AESO considers that, in this situation, these facilities should be classified as participant-related, regardless of whether they are "looped" facilities or not.

291 The AESO further considers that it is appropriate for market participants with connection projects that have radial facilities to pay the full cost of such facilities, regardless of whether or not there is a plan to loop the facilities in five years. Due to the variability and potential changes that occur to planned in-service-dates for system transmission facility upgrades that may be listed in a LTP or in a filed system NID, reliance on these documents to have costs classified as system-related cost becomes problematic.

292 Additionally, there are many circumstances that might result in "planned" system transmission facilities not being ultimately constructed. The reasons for this can include the failure of connection projects to materialize, regional load growth that is lower than forecast, and other potential circumstances pertaining to planning and forecasting. Therefore, the AESO is proposing that the market participant pay the full costs of radial facilities, with a refund due to the market participant if those facilities are subsequently looped within 20 years of the energization of the original market participant's facilities. The calculation of this refund is discussed in Section 7.5 below.

293 The AESO is also proposing to clarify subsection (3)(c) to more accurately reflect the intent of this section. In the AESO's view, the present wording may be confusing as it may be interpreted to suggest that the AESO is only required to propose connection facilities that are the minimum required to serve the requesting market participant, irrespective of existing system transmission facilities and the AESO's broader transmission system planning obligations.

294 The AESO added a new provision to proposed subsection 4.2(2)(m) to address the allocation of project costs regarding isolated communities regulated under the *Isolated Generating Units and Customer Choice Regulation*. The AESO considers that the costs to connect an isolated community should be participant-related costs. The AESO also notes that investment in those facilities would be calculated based on an economic analysis of the cost of continuing to serve the community with isolated generation, with pool price credits calculated under the *Isolated Generating Units and Customer Choice Regulation*, compared to the cost of building the new facilities to connect a community.

7.5 Section 9 – Changes to System Access Service After Energization

295 The AESO proposes substantive revisions to the current section 9, renumbered as section 5 and renamed as *Changes to System Access Service*. As a result of the AESO's proposal to require market participants to execute SAS agreements earlier in the connection process, any cancellations under Rate DTS will result in the load market participant having to either (i) pay the Rate DTS rate for five years from the cancellation notice date; or (ii) make a payment in lieu of notice ("PILON"), representing a share of system costs over the five year planning horizon.

296 In addition to revisions to the PILON provision, the AESO proposes to revise the "Shared Facilities" provisions of current subsection 5. Currently, the provisions are specific to transmission facilities that are constructed to serve a market participant and then used to serve other market participants, within five years of commercial operation of the original market participant's connection project. Under the AESO's proposed revisions these shared facilities could also include a connection project that was initially radial, and later looped for the purposes of addressing system transmission enhancements. In this way, the connection project would be responsible for the costs of the radial connection for the time of use solely for that market participant, given the use of the facilities over a 20 year period, and

the market participant would be refunded a portion of the cost of the radial facilities upon energization of the looped system transmission facilities.

297 Section 7.4.2 of this application describes the rationale for removing the provisions in section 8 of the current ISO tariff, *Construction Contributions for Connection Projects*, that refer to radial transmission facilities that are planned to be looped within five years. The AESO proposes that the connection costs of facilities that are initially radial be classified as participant-related costs. If radial transmission facilities are ultimately looped for a system transmission facility required by the AESO, the market participant will receive a refund. This refund will be calculated based on the length of time, over the 20 year period, that the market participant had sole use of the radial facilities, and energization of the system transmission facility upgrade.

7.6 Section 10 – Generating Unit Owner's Contributions

298 The AESO proposes substantive revisions to the current section 10 (now renumbered as section 7) to incorporate modernized language, provide clarity and remove language duplicated in other AESO authoritative documents.

299 The rate calculations and rates for a generating unit owner's contribution ("GUOC") have to this time been posted in a document on the AESO website. The AESO has since determined that rates should be included in the ISO tariff and accordingly is proposing to include in the terms and conditions the GUOC contribution rates shown in Table 7-1 below:

Table 7-1 – 2018-2020 Generating unit owner's contribution rates

Planning Region	Current (2010-2011) Rate ($/MW)	Proposed Rate ($/MW)
Northwest	$10,000	$10,000
Northeast	$50,000	$20,000
Edmonton	$32,500	$30,000
Central	$22,400	$50,000
Calgary	$10,000	$40,000
South	$25,000	$20,000

7.6.1 Capacity subject to generating unit owner's contribution rate

300 The first significant proposed revision is to the capacity used to calculate a GUOC contribution. Currently this capacity is the contract capacity under Rate STS, *Supply Transmission Service*. The AESO is proposing to use following capacity:

(a) **Maximum Capability** of a new generating unit if only a generating unit is being added at a site; or

(b) **Maximum Capability** of a new generating unit less the minimum capacity of new load being added at the same time at the same site or is proposed to be added within 12-months of the added generation.

301 This change would result in transmission connected dual-use connections (i.e. market participants with both load and generation) 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).

7.6.2 Generating unit owner's contribution rate determination

302 The second significant proposed revision is to a GUOC rate calculation method. In the past tariffs for 2006-2007, 2008-2009 and 2010-2011, the rate was calculated using forecast regional peak load, future regional net generation based on signed construction commitment agreements (CCA), generation surplus using the forecast regional peak load and future regional net generation, distance between major regional load centers, and dominant path adjustments to determine direction of generation flow.

303 The AESO has identified multiple concerns with this method. The use of this method was reasonable when most generation consisted of large fossil fuel powered controllable generating units with predictable marginal cost-based energy market offers located in few well defined geographical areas, and regional winter peak load was the primary determinant of generation flow. Therefore, knowing forecast regional (winter) peak load and future regional net generation alone was sufficient to reasonably approximate generation flow.

304 Now that regional summer peak load is approaching regional winter peak load, both can affect generation flow from a load perspective. In recent years, a large amount of wind and solar generation and generation co-located with load has been added to the AIES. Wind and solar powered generation is not coincident with regional winter peak load or regional summer peak load. It is uncertain how much wind and solar generation would be available at the time of regional winter peak load or regional summer peak load. Direction of generation flow is also increasingly influenced by hourly energy market merit order. Wind and solar generation is usually a price taker (i.e. offers at $0/MWh), while generation co-located with load and imports participate in the energy market depending on hourly pool price. This hourly energy market merit order, along with the hourly wind and solar generation level, determines generation flow from a generation perspective, rather than future regional net generation.

305 Since generation is not required to pay the costs of the transmission system, signed construction commitment agreements by supply market participants alone does not provide certainty that particular generation projects will be in-service as originally proposed. The payment of a GUOC contribution reduces the risk that a proposed generation project will not proceed. The AESO would accordingly include all generation that has paid GUOC contribution in its analysis to determine GUOC rates.

306 The AESO considers that using forecast flows from engineering studies to determine a generating unit's contribution rates is more appropriate. The AESO routinely performs engineering studies that take into account information such as winter regional peak load, summer regional peak load, summer regional light load, high/low wind powered generation, high/low imports, transmission constraints, underway and planned system transmission facility upgrades, and future generation. Results of these engineering studies provide a much more robust approximation of generation flows compared to the AESO's previous methodology. The AESO has recently performed these engineering studies in response to load and generation transmission SASRs and in order to begin preparing the AESO's next LTP. The AESO proposes to use a qualitative method to determine a GUOC contribution rate, as presented in Table 7-1 above. The following paragraphs explain the rationale for the proposed rates.

Northwest planning region

307 All prior AESO LTPs and more recent engineering studies have indicated that new generation in the Northwest planning region is desirable. The AESO accordingly proposes to assign the lowest GUOC contribution rate of $10,000/MW to the Northwest planning region.

Northeast planning region

308 The AESO's recent engineering studies indicate that after the Fort McMurray West 500kV transmission project is completed, the Northeast planning region transmission system would accommodate a significant amount of new generation at minimal to no cost. The AESO accordingly proposes to assign a low GUOC contribution rate of $20,000/MW to the Northeast planning region.

Edmonton planning region

309 The AESO's recent engineering studies indicate intermediate outflow capability for the Edmonton planning region. The AESO accordingly proposes to assign a medium GUOC contribution rate of $30,000/MW to the Edmonton planning region.

Central planning region

310 There is currently limited transmission capacity in the central east area of the Central Planning Region of the province. The AESO is in the process of developing transmission system upgrade alternatives that would address this issue but these alternatives will take a number of years to be completed. The AESO accordingly proposes to assign the highest GUOC contribution rate of $50,000/MW to the Central planning region.

Calgary planning region

311 The AESO's recent engineering studies indicate minimal outflow capability for the Calgary planning region after recent integration of the Shepard generating units. The AESO accordingly proposes to assign a high GUOC contribution rate of $40,000/MW to the Calgary planning region.

South planning region

312 The AESO's recent engineering studies indicate that the existing South planning region transmission system can accommodate a significant amount of new generation at minimal to no cost. The AESO accordingly proposes to assign a low GUOC contribution rate of $20,000/MW to the South planning region.

7.7 Administrative revisions

313 The AESO proposes revisions in several sections of the proposed terms and conditions that are minor and administrative in nature, in order to incorporate modernized language, improve clarity, and improve consistency with other ISO authoritative documents. Some of these changes are explained below.

7.7.1 Section 1 – Applicability and Interpretation of ISO Tariff

314 The proposed changes to the current section 1 reflect modernized language and are administrative in nature.

7.7.2 Section 2 – Provision of and Limitations to System Access Service

315 The AESO proposes the consolidation of the current sections 2 and 3 because they address similar subject matters. The consolidated sections are renumbered as section 2 and renamed as *Provision of System Access Service*.

316 Under proposed subsection 2.5(2)(c), the AESO proposes an addition to the list of events that may cause interruption or limitation of SAS to include a RAS. Activation of a RAS may impact a market participant whose connection required the RAS as well as other market participants.

317 The AESO is proposing changes to the current subsection 5(3) to clarify that if a market participant chooses a tapped configuration connection, the market participant is accepting less outage scheduling flexibility than if it chooses to connect with a full substation.

7.7.3 Section 3 – System Access Service Connection Requirements

318 As noted above, the AESO proposes the consolidation of the current sections 2 and 3.

319 The AESO proposes changes to the current subsection 2(2) of section 3 (now proposed subsection 2.8(1)) to specify that a market participant must comply with the AESO's technical requirements and functional specifications.

320 The AESO proposes to delete the current subsection 2(1) of section 3 because it is duplicative of the requirements of section 20.8 of the Act, that market participant must comply with (a) the ISO rules; and (b) the reliability standards, as well as section 101 of the ISO rules, *Interpretation*, which provides that the ISO rules are binding on (a) market participant; and (b) the ISO.

321 The AESO proposes changes to the current subsection 5 of section 3 (now proposed subsections 2.8(3) and (4)) regarding the consequence of a market participant's failure to comply with a technical requirement or functional specification.

7.7.4 Section 5 – Financial Obligations for Connection Projects

322 The AESO proposes a number of changes to the current section 5 (renumbered as section 6).

323 The AESO proposes to move the current subsection (2)(8) to proposed subsection 3.5.

324 The current subsection 3(2) should be deleted because it is duplicative and already addressed in current subsection 3(1).

325 The AESO proposes to delete the current subsection 5(3) because the mandatory obligation imposed by that subsection is contrary to the permissive words of section 41 of the *Transmission Regulation* which provides:

> ***Recovery of other secondary costs***
>
> *41(2) In addition to its duties under section 17 of the Act, the ISO <u>may</u> do either or both of the following:*
>
> > *(a) certify to the Commission that a cost was incurred under subsection (1);*
> >
> > *(b) notify the Commission of any concern the ISO has with respect to a cost referred to in subsection (1),*
>
> *but the Commission must not require the ISO to make any statement with respect to the prudence of a TFO or a DFO in incurring a cost under subsection (1).*

[Emphasis added]

326 The *Transmission Regulation* uses the discretionary word "may", while the current wording of the tariff provision is mandatory, "must", and the legislative wording prevails. In addition, the AESO considers it be unnecessary to revise the current subsection 5(3) to provide for permissive wording because the AESO's duty is fully addressed in the *Transmission Regulation* and therefore subsection 5(3) can be deleted.

7.7.5 Section 6 – Metering

327 The AESO proposes to delete the current section 6 in its entirety. The *AESO Measurement System Standard* referred to in the current subsection 2(1) of section 6 has expired and is no longer in effect. The AESO's current practice is to deal with metering requirements and associated compliance through its functional specifications. Efforts to develop a new rule regarding metering are currently underway.

7.7.6 Section 7 – Provision of Information by Market Participants

328 The AESO proposes to eliminate the current section 7 by moving the current subsections 2(1) and 4 into proposed section 2 and deleting the current subsection 3. The AESO proposes to delete the current subsection 3(1)(b) as it is duplicative of Section 306.4, *Transmission Planned Outage Reporting and Coordination* and Section 306.5,*Generation Outage Reporting and Coordination* of the ISO rules. The AESO also proposes to delete the current subsection 3(1)(c) because section 14 of the *Transmission Regulation* addresses the obligations of TFOs and DFOs to assist the AESO with preparing forecasts.

7.7.7 Section 12 – Demand Opportunity Service

329 The AESO proposes minor revisions to the current section 12 (renumbered as section 9).

330 The AESO proposes to make the current subsection 2(3) discretionary in order to provide the AESO with flexibility when the circumstances warrant. In addition, the AESO proposes changes to the current subsection 3(1) to clarify a market participant's obligation. In the AESO's view, the current wording regarding "a clear, through and convincing case, with supporting facts" appears to create a different burden than elsewhere in the tariff, and may cause confusion.

7.7.8 Section 13 – Financial Security, Settlement and Payment Terms

331 The AESO proposes minor revisions to current section 13 (renumbered as section 10 and renamed as *Settlement and Payment Terms*) to incorporate modernized language, improve clarity, and remove language duplicated in other AESO authoritative documents.

332 Financial security provided by market participants, for the purpose of settlement, is addressed in section 103.3 of the ISO rules, Financial Security Requirements, and should not be duplicated in the ISO tariff.

333 The AESO has revised subsection 10.3 in particular to reflect proper application of defined terms **point of delivery** or **point of supply.**

7.7.9 Section 14 – Peak Metered Demand Waivers

334 The AESO proposes minor revisions to the current section 14 (renumbered as section 11) to delete the current subsection 3(3), as its content is process-orientated and is already addressed in an AESO information document.

335 The AESO proposes to add more clarity regarding load restoration activities. Load restoration activities are for DFOs to manage load reliability for distribution customers without ratchet penalties. Subsection 2(1)(d) and (e) will allow other customers that are not DFOs to avoid ratchets if there is an ISO directive.

336 The AESO proposes to change the mandatory requirement in the current subsection 3(4) (renumbered as subsection 11.3(3)) for the AESO to request more data to "may request" in order to streamline the peak metered demand waiver request process to place accountability to retain distribution facility outage information on the DFO.

7.7.10 Section 15 – Miscellaneous

337 The AESO proposes minor revisions to the current section 15 (renumbered as section 12) to incorporate modernized language and improve clarity.

7.8 Other changes

7.8.1 System access service agreements

338 The AESO is proposing revisions to the SAS agreement proformas (Appendix B of the proposed ISO tariff) to better align the agreements with their purpose and streamline the need to repeatedly amend existing agreements.

339 The purpose of the SAS agreements is primarily to establish the point of supply or delivery and contract capacity of a substation, for generators (Rate STS), load (Rate DTS) and dual-use market participants. The proposed amendments maintain this information and remove all project cost information.

340 The AESO currently documents connection project cost information in the construction contribution decision ("CCD"), which is updated periodically until final costs are determined. The AESO prepares the CCD pursuant to Section 8 of the current ISO tariff. The connection project costs information is currently being replicated from the CCD into the SAS agreements, requiring amendments to a SAS agreement each time connection project costs are updated. The AESO has determined that it would be more efficient to remove connection project cost information from the SAS agreements and maintain them in the CCD, where it is already being captured. As such, the AESO proposes to amend the pro-forma SAS agreements to remove all connection project cost related information, and to primarily reflect the market participant's capacity request.

341 Further revisions to the remaining proformas are proposed to provide added clarity.

7.8.2 Abbreviated Needs Approval Process

342 The ANAP enables the AESO to approve a SASR rather having to obtain the Commission's approval through the NID approval process.[49] The AESO may approve a SASR under the ANAP if the request meets the eligibility criteria in section 501.3 of the ISO Rules, *Abbreviated Needs Approval Process*.

343 The AESO connection process continues to be followed for an ANAP eligible project as with any connection project. The AESO is proposing minor changes to the current terms and conditions to accommodate the ANAP, specifically, subsections 3.6(1) and 3.8.

7.8.3 Market participant choice

344 The market participant choice ("MPC") process is one option market participants may choose to follow to connect to the transmission system. The AESO facilitates this process to ensure that all market participants seeking a connection to the AIES are provided open and fair access.

345 On March 1, 2014, the AESO implemented a new MPC process. The new process reflects some variations to the connection process which allows greater flexibility for market participants in the project lifecycle. This process allows a market participant to build an agreed-to portion of their own transmission connection facilities while maintaining the integrity and reliability of the transmission system. Similar to the connection process, the MPC process involves formal stages and follows a gated approach. Key activities are required in each stage that must be completed to pass the gate for that stage.

[49] Authority and requirements for ANAP are found in section 11(4)(5.1) of the *Transmission Regulation* and section 501.3 of the ISO rules, *Abbreviated Needs Approval Process.*

346 The AESO has identified certain tariff provisions that should be updated to be in alignment with the MPC process. The AESO has identified revisions in the proposed subsection 4.6(6) to remove the requirement of a MPC project to pay a construction contribution to a TFO and proposed subsection 6.4(1)(b) removes the requirement for a MPC project to provide financial security.

7.8.4 Transmission direct connected distribution customers

347 The current terms and conditions limit the ability of a TFO to interact and transact directly with a direct connected distribution market participant.

348 In early 2014, FortisAlberta and AltaLink developed process improvements in an effort to reduce connection project cycle times. The process would require FortisAlberta customers to execute a Construction Commitment Agreement ("CCA") directly with AltaLink, thus removing FortisAlberta from being involved in the connection project.

349 With this proposal, FortisAlberta would continue to have the accountability for the SAS agreement with the AESO. In addition, FortisAlberta would continue to execute an Electric Service Agreement ("ESA") with the FortisAlberta customers. The CCA relationship between the FortisAlberta customer and AltaLink would terminate when the project is commissioned and an ESA has been executed.

350 The AESO notes that the current terms and conditions do not contemplate this and the AESO has identified certain tariff provisions that refer to obligations of the market participant (in this case being FortisAlberta). To this end, the AESO is proposing changes to provisions to accommodate the connection process change proposed by AltaLink and FortisAlberta.

351 If FortisAlberta remains the holder of tariff obligations throughout the connection process, the identified obligations may be addressed through language in the tariff such as, "The market participant must ensure financial obligations are satisfied during the connection process." FortisAlberta could then enter into a contractual arrangement with the end-use customer under which the end-use customer would commit to satisfying the obligations. Table 7-2 below identifies the current and proposed subsections which were revised to ensure that market participants can continue to meet the ISO tariff obligations:

Table 7-2 – Proposed revisions for transmission direct connected distribution customers

Current subsection	Proposed subsection
current subsection 2(1) of section 5: A **market participant** must **provide financial security** and **construction contribution** as described in the following subsections, which **financial obligations** are illustrated:	proposed 6.2(1): A **market participant** must ensure that its **financial obligation**, which consists of the **financial security** and **construction contribution**, excluding the amount of any advancement costs calculated by the **ISO** pursuant to subsection 4.2(3)(a) of the **ISO tariff**, *Classification and Allocation of Connection Projects Costs*, are provided as described in the following subsections, which **financial obligations** are illustrated:
current subsection 2(2) of section 5: A **market participant** must satisfy the **financial obligation** for a connection project at all times after the **ISO** determines the connection project scope in accordance with subsection 3(3) of section 4 of the **ISO** tariff, *System Access Service* Requests.	proposed 6.2(2): The **market participant** must ensure that the **financial obligation** for a connection project is satisfied at all times after the **ISO** determines the connection project scope in accordance with subsection 3.3(3) of the **ISO tariff**, *System Access Service Requests*.
current subsection 2(8) of section 5: The **market participant** and the **legal owner** of the **transmission facility** must enter into the construction commitment agreement for the connection project except where the **ISO** waives the requirement for construction commitment agreements between a **legal owner** of an **electric distribution system** and a **legal owner** of **transmission facilities** who are **affiliates.**	proposed 3.5(1): The person providing **financial security**, **construction contribution** or both for a connection project must enter into a *Construction Commitment Agreement*, substantially in the form included in Appendix B of the **ISO tariff**, *System Access Service Agreement Proformas* with the **legal owner** of a **transmission facility**, unless: (a) the **market participant** is a **legal owner** of an **electric distribution system**; or (b) the **market participant** and the **legal owner** of the **transmission facility** are **affiliates**.
current subsection 2(8) of section 5: The **legal owner** of the **transmission facility** must maintain records of the construction commitment agreement, **financial security** and **construction contribution** related to the	proposed 3.5(2): The **person** providing **financial security**, **construction contribution** or both for a connection project must provide the **ISO** with an executed copy of a *Construction Commitment*

Current subsection	Proposed subsection
connection project and provide a copy of those records to the **ISO** upon request.	*Agreement* referred to in subsection 3.5(1), as well as a record of the **financial security** and **construction contribution** unless the **legal owner** of the **transmission facility** provides a copy of the same to the **ISO**.
current subsection 4(1) of section 5: The **market participant** must pay as a **construction contribution:**	proposed 6.5(1): The **market participant** must ensure a **construction contribution** is paid for:
current subsection 4(2) of section 5: The **market participant** must pay the **construction contribution:**	proposed 6.5(2): The **market participant** must ensure the **construction contribution** is paid:
current subsection 4(3) of section 5: The **market participant** must pay the **construction contribution** in amounts greater than those documented in schedule "A" of the construction commitment agreement required by subsections 2(7) above.	proposed 6.5(3): The **market participant** may ensure the **construction contribution** is paid in amounts greater than those documented in "Schedule A" of the *Construction Commitment Agreement* required by subsection 6.2(7) above.
current subsection 5(1) of section 5: The **market participant** must, upon cancellation of a connection project at any time prior to **commercial operation**, pay:	proposed 6.6(1): The **market participant** must, upon cancellation of a connection project at any time prior to **commercial operation**, ensure payment of:
current subsection 5(2) of section 5: The **legal owner** of the **transmission facility** must, upon failure by a **market participant** to pay the costs described in subsection 5(1) above before or on the payment due date as specified by the **legal owner** of the **transmission facility**:	proposed 6.6(2): The **person** who provided the **financial security**, **construction contribution** or other amounts accepts that the **legal owner** of the **transmission facility** must, upon failure of payment of the costs described in subsection 6.6(1) above before or on the payment due date as specified by the **legal owner** of the **transmission facility**:
current subsection 5(4) of section 5: The **legal owner** of the **transmission facility** must return to the **market participant** any **financial security**, **construction contribution** or other amounts paid by the **market participant** in excess of the costs described in subsection 5(1) above.	proposed 6.6(4): The **person** who provided the **financial security, construction contribution** or other amounts is entitled to the return of any **financial security**, **construction contribution** or other amounts by the **legal owner** of the **transmission facility** that is in excess of the

Current subsection	Proposed subsection
	costs described in subsection 6.6(1) above.
current subsection 5(5) of section 5: The **legal owner** of the **transmission facility** may deem a connection project to be cancelled pursuant to subsection5(1) above if a **market participant** takes action that, in the opinion of the **legal owner** of the **transmission facility**, indicates the **market participant** has terminated or abandoned its intention to proceed to **commercial operation** of the connection project.	proposed 6.6(5): A connection project may be deemed to be cancelled pursuant to subsection 6.6(1) above if a **market participant** or other **person** takes action that, in the opinion of the **legal owner** of the **transmission facility**, indicates the termination or abandonment of an intention to proceed to **commercial operation** of the connection project.
current subsection 5(6) of section 5: The **legal owner** of the **transmission facility** may deduct, set off and net out any debts, liquidated demands, unliquidated demands, damages or other amounts the **legal owner** of the **transmission facility** owes to the **market participant**, under any construction commitment agreement between the **legal owner** of the **transmission facility** and the **market participant**, in partial or full satisfaction of any costs owing by the **market participant** under subsection 5(1) above.	proposed 6.6(6): The **person** who provided the **financial security, construction contribution** or other amounts accepts that the **legal owner** of the **transmission facility** may deduct, set off and net out any debts, liquidated demands, unliquidated demands, damages or other amounts the **legal owner** of the **transmission facility** owes to the **market participant** or other **person**, under any *Construction Commitment Agreement* between the **legal owner** of the **transmission facility** and the **market participant** or other **person**, in partial or full satisfaction of any costs owing by the **market participant** or other **person** under subsection 6.6(1) above.
current subsection 6(1) of section 5: The **legal owner** of the **transmission facility** must return any **financial security** held for the connection project to the **market participant**, within ninety (90) **days** after **commercial operation** of the connection project.	proposed 6.7(1): The **person** who paid the **construction contribution** is entitled to the return of any **financial security** held for the connection project by the **legal owner** of the **transmission facility**, within 90 **days** after **commercial operation** of the connection project.
current subsection 6(2) of section 5: The **legal owner** of the **transmission facility** must return to the **market participant** any **construction contribution** paid by the **market participant** in excess of the actual cost of the connection project, within ninety (90) **days** after the legal owner of the transmission facility provides the final cost report for the connection	proposed 6.7(2): The **person** who paid the **construction contribution** is entitled to the return of any **construction contribution** paid in excess of the actual cost of the connection project by the **legal owner** of the **transmission facility**, within 90 **days** after the **legal owner** of the **transmission facility** provides the final cost

Current subsection	Proposed subsection
project to the **ISO**.	report for the connection project to the **ISO**.
current subsection 7(1) of section 5: A **market participant** must satisfy a request for **financial** security or **construction** contribution or for additional or replacement **financial** security or **construction** contribution, within thirty (30) **days** of such request.	proposed 6.8(1): A **market participant** must ensure a request for **financial security** or **construction contribution** or for additional or replacement **financial security** or **construction contribution** is satisfied within 30 **days** of such request.
current subsection 7(2) of section 5: A **market participant** must report any event of default by it to a lender for borrowed funds or any **material adverse changes** in its financial position within two (2) **business days** of such event.	proposed 6.8(2): A **person** who provides **financial security** or **construction contribution** for a connection project must report any event of default by it to a lender for borrowed funds or any **material adverse changes** in its financial position within 2 **business days** of such event.
current subsection 7(3)(a) of section 5: (a) A **market participant** fails to provide **financial security** or **construction contribution**: or	proposed 6.8(3)(a): a **market participant** fails to ensure **financial security** or **construction contribution** is provided; or
current subsection 7(4) of section 5: The **legal owner** of the **transmission facilities** must continue the suspension of work on the connection project until the **market participant** provides the required **financial security** or **construction contribution** or the **market participant's** financial position is reassessed, as appropriate.	proposed 6.8(4): A **market participant** must accept the continued suspension by the **legal owner** of the **transmission facilities** of work on the connection project until the required **financial security** or **construction contribution** is provided or the financial position of the **person** who provided **financial security** or **construction contribution** no longer constitutes a **material adverse change**
current subsection 7(6) of section 5: The **market participant** must continue to meet all **financial obligations** for amounts that have accrued or are accruing, to the **ISO** or to the **legal owner** of the **transmission facility** with respect to the connection project, notwithstanding any suspension of work on the connection project under subsection 7(3) above.	proposed 6.8(5): The **market participant** must continue to ensure all **financial obligations** are met for amounts that have accrued or are accruing, to the **ISO** or to the **legal owner** of the **transmission facility** with respect to the connection project, notwithstanding any suspension of work on the connection project under subsection 6.8(3) above.
current subsection 7(2) of section 8:	proposed 4.6(2):

Current subsection	Proposed subsection
A **market participant** must pay **construction contribution** amounts to the **legal owner** of the **transmission facility** in accordance with the **financial obligation** provisions of section 5 of the **ISO tariff**, *Financial Obligations for Connection Projects.*	Subject to subsection 4.6(6) below, a **market participant** must ensure that **construction contribution** amounts are paid to the **legal owner** of the **transmission facility** in accordance with the **financial obligation** provisions of section 6 of the **ISO tariff**, *Financial Obligations for Connection Projects*.

8 Other matters

8.1 Cost recovery of CIP Alberta reliability standards

8.1.1 Background

352 Alberta Reliability Standard CIP-002-AB-5.1, *BES Cyber System Categorization* ("CIP reliability standard") is an AESO reliability standard that imposes certain physical and cyber security requirements on a number of Alberta generating units. In Decision 3441-D01-2015, the Commission approved the CIP reliability standard, effective October 1, 2017.

353 On September 29, 2014, the AESO requested that the Commission provide advice and directions on the issue of cost responsibility for compliance with the CIP reliability standard.[50]. In paragraph 6 of its December 9, 2015 disposition letter, the Commission directed the AESO to address the issue of cost responsibility for compliance with the CIP reliability standards as part of its next tariff application:

> *"The AESO's application must either state that the AESO is including any such costs in its proposed tariff as recoverable under the AESO's tariff pursuant to section 30(2)(a)(iv) of the Electric Utilities Act, or that the AESO does not propose that some or all of such costs are recoverable through its proposed tariff. The AESO must provide the rationale for its position. In this way, if the AESO does not propose that such costs are recoverable through its proposed tariff, any directly affected party may register to participate in the proceeding and advance its position, stating its bases for and quantifying its claim to recover them."*[51]

354 Three levels of BES cyber system impacts exist in the CIP reliability standard: low, medium and high. All generators in Alberta have been identified as low impact BES cyber systems except for the Sundance generation facility, which has been identified as a medium impact BES cyber system under the CIP reliability standard. The AESO anticipates that the cost of compliance for generators with low impact BES cyber systems to be relatively small.

355 In Proceeding 3443, TransAlta, the owner and operator of the Sundance generation facility, reported that complying with the CIP reliability standard would result in both implementation costs of approximately $5 million, and ongoing annual maintenance costs of approximately $1 million. During Proceeding 3443, it was expected that the Sundance generation facility would be retired in 2026-2027. Since Proceeding 3443 closed, TransAlta has notified the AESO that TransAlta intends to retire Sundance Unit 1 effective January 1, 2018, and mothball Sundance Unit 2 effective January 1, 2018, for a period of two years.

8.1.2 Cost recovery analysis

356 For the reasons that follow, the AESO has determined that the costs of complying with the CIP reliability standard are not recoverable under the ISO tariff, and are the responsibility of an affected generating unit owner. The AESO arrived at its determination by examining and considering: (i) applicability of CIP reliability standards, (ii) whether there are any applicable legislative or regulatory requirements regarding compliance cost responsibility; and (iii) whether, under a value analysis, there would be a benefit that would support cost recovery for reliability, economic efficiency, or other reasons.

(i) Applicability of new reliability standard

357 In general, exempting existing facilities from the application of new reliability standards that will apply to future facilities represents discrimination between market participants as a result of applying ISO

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[50] Proceeding 3443, Exhibit 0005.00.AESO-3443 at para 5.
[51] Proceeding 3443, Proceeding 3443 disposition dated December 9, 2015 at para 6.

rules or Alberta reliability standards unequally to market participants based on the vintage of their facilities. Accordingly, the AESO is of the view that there should be a presumption that new requirements will apply to all applicable facilities and the owners of existing facilities should understand that they do not have a vested right to be exempted from all changes in technical standards or requirements that may have cost consequences to them.

358 In Proceeding 3441, the AESO explained the need for the CIP reliability standard and the severity of the risk of operating in the absence of the CIP reliability standard. In Decision 3441-D01-2015, the Commission approved the CIP reliability standard with a two-year implementation period, finding that that no interested person had satisfied the Commission that the AESO's recommendation to approve the CIP reliability standard was not in the public interest. Accordingly, as of October 1, 2017, the new requirement applies to all generating unit owners in Alberta.

(ii) Legislative and regulatory requirements

359 There are no express legislative or regulatory requirements that impose upon the AESO an obligation to pay compensation to generation owners that incur CIP reliability standard compliance costs.

360 In fact, the current subsection 3(2)(b) of section 3 indicates that costs of this nature should be borne by the market participant:

> *Facilities Owned by a Market Participant*
>
> *3(2) A market participant is responsible for any costs arising from changes to its facilities required as a result of:*
>
> *…*
>
> *(b) changes to requirements, obligations and guidelines that apply to the connection, subject to subsection 3(3) below, or …*

(iii) Value analysis

361 The AESO's value analysis is contextual and fact specific and will address the potential loss of system reliability, fairness, effect on open competition, opportunity to account for and minimize costs, effective price signals, cost causation and consistency of treatment.

<u>Potential loss of system reliability</u>

362 The CIP reliability standards are being implemented to ensure adequate system security. However, costs for complying with reliability standards and technical requirements will have an effect on the price signal, which includes a potential effect on retirement and investment signals to market participants. In the long-term, retirement and investment signals serve to ensure supply adequacy. In the short-term, if the cost of complying with the CIP reliability standard causes the owner of the affected unit to derate or retire, it may result in a risk to supply adequacy. However, if the costs of complying with the CIP reliability standard caused the Sundance generating facility to be retired, the AESO expects that there would be no resulting reliability concerns for the AIES. In other words, the AESO considers there to be no reliability rationale for the AESO to pay to have the Sundance generating facility remain on-line as this is the choice of the market participant.

<u>Fairness</u>

363 The rationale for requiring facility owners to implement CIP reliability standards is security and, accordingly, the associated costs should be borne by generating facility owners. The AESO submits that matters such as sizing and configuration, of generating facilities, which result in a low, medium or

high impact BES cyber system designation under the CIP reliability standard, can and should be managed by the company. The AESO considers it to be fair treatment to reasonably apply ISO authoritative documents consistently and equally across all types of market participants.

Effect on open competition

364 On a go-forward basis, the principle of supporting open competition will be upheld by assigning the cost of adhering to reliability standards and technical requirements to the market participant as long as the criteria for how such costs will be applied are predictable and understandable. However, requiring the owner of incumbent assets to incur unexpected costs that were not known to them at the time that they made capital investment decisions increases regulatory risk for both new entrants and incumbent market participants and, depending on the degree of this risk, may be considered to be a barrier to market entry. The impact of this potential barrier to entry on open competition depends on the magnitude of unexpected costs and also the degree to which bearing such costs unduly discriminates between market participants (i.e., is there a significant difference between the costs that must be borne by different market participants). The AESO considers that the barrier to entry that materializes when requiring incumbent assets to adhere to CIP standards is outweighed by ensuring adequate reliability and system security.

Opportunity to account for and minimize costs

365 If the costs of complying with CIP reliability standards are borne by market participants, new entrants can make economically efficient investment decisions that should account for the cost of implementing CIP requirements when sizing or configuring their proposed facilities. For an owner of incumbent assets, the option to re-size a generating unit to take into account the increased cost of adhering to the new CIP standards associated with a greater size is limited. However, when multiple generating units are configured such that a higher impact BES cyber security system is triggered, the market participant has a number of options: (i) it can reconfigure its facility to meet a lower impact level of the CIP standard; or (ii) implement the CIP requirement for the higher standard. In the second situation, the market participant is in the best position and has the incentive to assess the most cost effective option to address the CIP reliability standard.

Effective price signals

366 The principle of maintaining effective price signals is upheld as the cost of enhancing or upgrading facilities to address the CIP reliability standards will eventually be reflected in the energy and ancillary service market offers of that market participant. This may exert upward pressure on the price and quantity offers from these participants and the long term impact on the price signal will ultimately be borne by consumers. The market participant bearing the cost will face an immediate impact and, depending on the magnitude of this impact, this may result in a signal to the owner of an incumbent asset to resize or to retire particular assets (whether or not retirement presents a supply adequacy risk is discussed above). In this manner, requiring generating unit owners (both incumbent and new-entrants) to pay for the cost of complying with the CIP reliability standard costs maintains an efficient price signal regarding sizing, configuration and economic life of generating facilities.

Cost causation – alignment of investment and operational decisions with compliance costs

367 Using cost causation assessments for assigning cost as they relate to reliability standards can be challenging because all market participants benefit from robust reliability standards. In the case of the CIP reliability standard, the relevant question in a cost causation assessment, is not “who benefits”, but “who decides whether to invest or not invest?” The Sundance generating facility creates a medium impact BES cyber risk to the AIES and the owner, TransAlta, is the only party that is empowered to make economically efficient investment and operating decisions regarding that facility.

The alignment of the investment decision maker to the bearer of the cost of compliance with the CIP reliability standard provides for the most economically efficient means to assess cost causation and assign cost.

<u>Consistency of treatment</u>

368 The AESO has historically required generating unit owners to pay for compliance costs for changes to Alberta reliability standards, technical standards, ISO tariff and ISO rules. Adherence to past approaches signals to investors that the AESO follows consistent principles in applying the ISO tariff for the provisions of system access service.

369 The AESO notes that interveners raised two prior Commission decisions in Proceeding 3443, namely Decision 2008-101 and Decision 2010-606, both of which concerned unique circumstances and which are not applicable to the issue of cost recovery for compliance with the CIP reliability standard.

370 Decision 2008-101 concerned an application for cost recovery for a generating unit owner regarding a specific, one-time transmission upgrade. No fair, efficient and openly competitive analysis was provided in that proceeding or addressed in the Commission's decision. In that proceeding, the Utilities Consumer Advocate ("UCA") requested that the Commission establish a general policy regarding the payment of direct costs to generator owners through the ISO tariff in the future. In its findings, the Commission held that:

> *"… on the basis of the evidence before it, that this application is unique. Consequently, [the Commission] does not see the need to develop a general policy at this time concerning payment for assets which are not part of the Transmission System."*

371 In the proceeding leading to Decision 2010-606, the AESO described the proposed Rider J, *Wind Forecasting Service Cost Recovery Rider*, as an "exception" from normal tariff charges:

> *"As other generators bear their own cost of providing forecast data, the AESO considers that wind generators should bear the cost of the wind forecasting service. The AESO proposes the wind forecasting service cost recovery Rider J to charge wind generators for costs arising from the wind forecasting service contract. The AESO notes that Rider J is an exception to its normal tariff charges, as legislative requirements (discussed in section 5.1 of this application) appear to have little applicability to the recovery of these costs. The cost of the wind forecasting service is not a cost of the transmission system, nor a cost arising from ancillary services, losses, or the AESO's own administration. Rather, it is a cost related to a service which could be arranged and managed by the wind generators themselves, but which can be more effectively and efficiently arranged and managed by the AESO. The AESO concluded, in consultation with market participants, that it was appropriate to recover such costs from wind generators. The simplest mechanism for such recovery is through a tariff rider, as other options (like a trading fee) cannot be easily differentiated to apply just to wind generators as a subset of market participants."*[52]

372 In that decision, the Commission observed that the AESO had decided that it can most efficiently and effectively arrange and manage the wind forecasting function rather than having wind generators do it themselves. Consistent with the principle of cost causation, and recognizing that wind generators should bear this cost, the Commission approved recovery of the wind forecasting services cost by way of the proposed Rider J was reasonable.[53]

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[52] Proceeding 530, Exhibit 0002.00.ISO-530 at para 318.
[53] Decision 2010-606 at para 322.

8.1.3 Conclusion

373 Based on the discussions above regarding the applicability of new reliability standards, legislative and regulatory requirements, and the AESO's value analysis, the AESO is of the view that the CIP reliability standard compliance costs are participant costs, and it is efficient, fair and reasonable for these costs to be paid by the applicable generating unit owner.

374 In the event that the Commission finds that some or all of the CIP reliability standard compliance costs are payable by the AESO to generating unit owners under the ISO tariff or by some other means, the AESO would require further direction from the Commission regarding the process and mechanisms to establish the prudency of compliance costs sought for recovery from the AESO. This is because the AESO does not have the authority to (i) compel an owner of an applicable generating unit to provide the necessary information to support a request for compliance cost recovery; or (ii) to make determinations regarding the prudency of compliance costs. The AESO is of the view that the Commission is authorized and best qualified to conduct a prudency review.

375 Further, the AESO would require direction from the Commission regarding the specifics of the mechanism that will be used to pay and recover the compliance costs.

376 The AESO's request for direction regarding cost recovery of the CIP reliability standard compliance costs was filed on September 29, 2014. The AESO anticipates that a decision for this 2018 General Tariff Application will be released in late 2018. This regulatory lag has resulted in regulatory uncertainty.

377 Going forward, the AESO requests that the Commission provide guidance regarding how applications for cost recovery for compliance with new ISO rules and reliability standards should be addressed.

378 The AESO is of the view that when cost recovery from rate payers is requested by market participants and the AESO does not support such cost recovery, market participants should file an application with the Commission to request approval of the proposed cost recovery. In such circumstances, the AESO would participate as an intervenor in the resulting Commission process. Where relevant, the findings of such a proceeding would then be included in the AESO's tariff applications.

379 Otherwise, in the rare circumstances where the AESO supports cost recovery from rate payers to an existing ISO rule or ISO tariff provision, and the existing ISO rule or ISO tariff provision does not provide the AESO with sufficient guidance or latitude to address the issue regarding cost recovery, it would be appropriate for the AESO to file an application with the Commission to justify and seek approval of what the AESO considers to be an appropriate cost recovery mechanism. This could be a singular application or combined with the AESO's comprehensive ISO tariff application, which would be at the AESO's discretion, and would be dependent on the filing date of the AESO's next comprehensive tariff application.

8.2 Tariff treatment for energy storage

380 Prompted by interest from stakeholders, the AESO launched an energy storage integration initiative in September 2012. Since then, the AESO has been exploring how energy storage facilities can connect to the transmission system and participate in the Alberta electricity market. The AESO's initial assessment identified and prioritized issues that may exist within the current industry structure related to energy storage integration. One of the priority issues identified was the system access service or services that should be applicable to energy storage when withdrawing electricity from the system (charging) and when supplying electricity to the system (discharging), including whether a new energy storage service should be created.

381 The AESO initially reviewed current legislation, recent Commission decisions regarding the ISO tariff, and the existing ISO tariff for guidance on the tariff treatment of energy storage facilities.

382 In its recommendation paper dated June 18, 2015, provided in Appendix Q of this application, the AESO concluded that the current legislative framework supports an energy storage facility being treated as alternating between supplying electricity to the transmission system (similar to a generator) and withdrawing electricity from the transmission system (similar to a load). An energy storage facility would therefore be charged for location-based cost of losses and comparable charges applicable to generators when supplying electricity (discharging) and would be charged for reasonable costs of the transmission system as applicable to load when withdrawing electricity (charging).

383 Treatment of an energy storage facility as a generator when it is supplying electricity to the transmission system and as a load when it is withdrawing electricity from the transmission system would also be comparable to the treatment of currently existing dual-use sites that include both generation and load. A dual-use site receives system access service under Rate STS, *Supply Transmission Service*, in an hour when it provides a net supply of electricity to the transmission system, and under Rate DTS, *Demand Transmission Service*, in an hour when it withdraws a net load from the transmission system. The AESO suggest similar "dual-use" treatment as a potential approach to providing system access service to an energy storage facility.

384 Although the legislative framework supports this approach, it does not provide any specific direction that would suggest whether the AESO's existing rates would be appropriate for application to energy storage facilities. The AESO considered that its existing rates may need to be modified or new rates may need to be developed to adequately address the characteristics of energy storage.

385 The AESO notes that recent Commission decisions regarding the ISO tariff have generally relied on cost causation as the basis for determining appropriate rates for system access service. To better understand the potential cost causation impacts of energy storage facilities, the AESO contracted for an operational and economic dispatch study of energy storage facilities.

386 The University of Calgary completed the study and provided its report to the AESO in May 2016, provided as Appendix O to this application. The study modelled the operation of eight energy storage facilities comprising different technologies and sizes, based on actual hourly merit orders over 260 weeks from January 2010 to December 2014. The study predicted the operation of the energy storage facilities in attempting to maximize profit through energy price arbitrage.

387 The dispatch modelling showed that the typical daily discharge-charge cycle of an energy storage facility had an indirect correlation with system demand, where supply to the transmission system tended to occur during high pool price hours (which correlated to higher system demand) and withdrawal from the transmission system tended to occur during low pool price hours (which correlated to lower system demand). However, the dispatch modelling also showed that withdrawal from the transmission system (charging) could occur during any hour of the day, including at close to the rated capacity of the energy storage facilities.

388 Based on examining the results of the study, the AESO drew the following conclusions with respect to cost causation:

(a) The cost causation basis for the bulk system charge in Rate DTS is coincidence with system peak;

- The Commission has found that system peaks are important in the planning of the bulk transmission system. If an energy storage facility charges (withdraws from the transmission system) during system peak, it could cause bulk system costs.

(b) The cost causation basis for the regional system charge in Rate DTS is load in any hour;

- The Commission has directed the AESO to use non-coincident peak demand, together with a ratchet, to collect regional system costs. If an energy storage facility charges (withdraws from the transmission system) in any hour, it could cause regional system costs.

(c) The cost causation basis for the point of delivery charge in Rate DTS is load in any hour;

- The Commission has directed the AESO to use a multi-tiered non-coincident peak demand, together with a ratchet, to collect point of delivery costs. If an energy storage facility charges (withdraws from the transmission system) in any hour, it could cause point of delivery costs.

(d) The cost causation basis for the operating reserve charge and the transmission constraint rebalancing charge in Rate DTS is load in the hour in which costs are incurred;

- The Commission has approved the hourly allocation of both operating reserve costs and transmission constraint rebalancing costs. Contingency reserve volumes vary directly with hourly load and hourly generation. If an energy storage facility charges (withdraws from the transmission system) in any hour, it could cause operating reserve costs and transmission constraint rebalancing costs.

(e) The voltage control charge in Rate DTS recovers transmission must-run costs as a variable cost through a $/MWh energy charge. The cost causation basis reflects the variable nature of transmission must-run costs that are affected by many factors; and

(f) The other system support services charge in Rate DTS recovers miscellaneous fixed costs through a $/MW demand charge. The cost causation basis reflects the fixed nature of those costs.

389 The AESO considers that this examination of cost causation supports the application of Rate DTS to energy storage facilities, in hours in which the energy storage facilities are withdrawing electricity from the transmission system (charging). In hours in which the energy storage facilities are supplying electricity to the transmission system, Rate STS would apply.

390 As the application of Rates DTS and Rate STS to energy storage facilities would be similar to their application to dual-use sites, the AESO also compared the typical discharge-charge behaviour of an energy storage facility to the supply and withdrawal behavior at dual-use sites. The AESO found that some dual-use sites exhibited similar supply and withdrawal patterns as energy storage facilities, supplying to the transmission system in higher pool price hours and withdrawing from the transmission system in lower pool price hours. As Rates DTS and Rate STS have been found to appropriately attribute costs to dual-use sites, the similarity of the supply and withdrawal patterns of energy storage facilities suggests that those rates may be appropriate for energy storage facilities as well.

391 The AESO further notes that many of the components of Rate DTS can be avoided or reduced through managed operation of an energy storage facility. For example, the AESO expects that an energy storage facility could:

- avoid bulk system charges by avoiding withdrawals from the transmission system during hours of coincident system peak;
- reduce regional system and point of delivery charges by reducing peak metered demand by limiting withdrawal (charging) rates to a lower value than supply (discharging) rates;

- reduce point of delivery charges through substation ownership (to provide primary service credits) and through contracting for both Rate DTS and Rate STS system access services (to provide a smaller substation fraction under Rate DTS); and
- reduce operating reserve and transmission constraint rebalancing charges by avoiding withdrawals from the transmission system during high pool price hours, which generally correlate to hours in which operating reserve and transmission constraint rebalancing charges are high.

392 The AESO's assessment suggests that, by implementing several of the operational measures discussed above, an energy storage facility would incur only about 12% of the costs that a similarly sized load-only service would incur under Rate DTS. The AESO considers that the availability of such reduction suggests the application of Rate DTS to an energy storage facility is reasonable.

393 During consultation for the originally filed 2018 ISO tariff application, energy storage proponents suggested that energy storage facilities should receive Rate DOS, *Demand Opportunity Service*, or be eligible for a new interruptible rate.

394 Rate DOS has well-established eligibility criteria set out in the current section 12, *Demand Opportunity Service*. The criteria in subsection 3(3) includes that Rate DOS must be used for additional electric energy either (a) to replace an alternative source of energy; or (b) to take advantage of a market opportunity where the alternative would be to forego the opportunity.

395 An energy storage facility has no alternative source of energy other than withdrawing from the transmission system when charging. As well, an energy storage facility cannot forego withdrawing from the transmission system and still be able to operate as an energy storage facility, thereby becoming unfeasible. Accordingly, the AESO is of the view that an energy storage facility is not eligible for Rate DOS.

396 Concerning the potential for a interruptible rate, the AESO considers that other market participants would similarly accept the risk of occasional interruption in return for system access service at a significant discount. However, many of the costs discussed above in the context of cost causation are not avoided through simple interruption of service. One of the costs which may be reduced through interruption of service is that of the bulk system, and the AESO notes a market participant may already avoid bulk system charges by avoiding coincident system peak. The AESO accordingly does not consider the provision of a new interruptible rate to be appropriate for energy storage service.

397 Finally, the AESO considers that both system access service and energy storage integration may be affected by the changes currently underway in the Alberta electricity market, including the transition to implement a capacity market. Further, the AESO is currently engaging stakeholders in a review of the bulk and regional tariff design and has indicated that a review of the applicable tariffs or opportunity services as they may relate to storage (or other technologies) will be part of this review. Therefore, the AESO will continue to monitor and respond to requests for system access service for energy storage facilities and believes it is appropriate to utilize the current Rate DTS and STS tariffs to accommodate energy storage facilities.

398 The AESO has reviewed the current ISO tariff as well as the proposed revisions in this application and, where appropriate, has updated applicability and other provisions to improve clarity around which rates and terms and conditions apply to energy storage facilities.

9 Responses to directions

399 The AESO's responses to Commission directions that directly related to the proposed tariff are included within sections 4, 5, 6, and 8 in this application.

400 For convenience of reference, Table 9-1 below summarizes the tariff-related directions that are addressed in this application. The table indicates the decision in which the direction was issued, and the section in this application in which the matter is addressed.

401 In the AESO's view, this application comprehensively addresses those directions listed in Table 9-1. The AESO requests that the Commission confirm that these outstanding directions have been adequately responded to.

Table 9-1 – Directions responded to in the Amended 2018 ISO Tariff Application

Direction	*Response*
Decision 2014-242 on 2014 ISO Tariff and 2013 ISO Tariff Update	
Exclude customer-owned projects The proposal of the DUC is denied. The AESO is directed to continue to exclude customer-owned projects from the database and POD cost calculations (paragraph 208).	Addressed in section 4.3.1 of this application
Update on direction 2 implementation The AESO is directed to use the full increased capacity made possible by an upgrade project. If the AESO cannot reasonably determine this capacity level for any given project, then the project should be excluded from the database (paragraph 260). **Decision 3473-D01-2015** The Commission has reviewed the AESO's response to Direction 2 and finds that it has resulted in unanticipated effects that could not have been known at the time of proceeding 2718. The AESO's proposal to delay the implementation of Direction 2 until the matter can be thoroughly explored is reasonable and both the UCA and Devon agree with this approach (paragraph 31).	Addressed in section 4.3 of this application
Long-term transmission rate projections The Commission finds the AESO's current practice to be helpful and the AESO is therefore directed to continue its current practice of providing its long-term transmission rate projections (paragraph 422).	Addressed in section 5.7 of this application
Rider C design The Commission acknowledges the view expressed by both the ADC and the DUC that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA (paragraph 704).	Addressed in section 6.1 of this application

Direction	*Response*
Proceeding 3443 disposition letter	
CIP Alberta reliability standard compliance costs The AESO is directed to address as part of its next general tariff application, the issue of cost responsibility for compliance with the CIP Alberta reliability standards. The AESO's application must either state that the AESO is including any such costs in its proposed tariff as recoverable under the AESO's tariff pursuant to section 30(2)(a)(iv) of the Electric Utilities Act, or that the AESO does not propose that some or all of such costs are recoverable through its proposed tariff. The AESO must provide the rationale for its position. In this way, if the AESO does not propose that such costs are recoverable through its proposed tariff, any directly affected party may register to participate in the proceeding and advance its position, stating its bases for and quantifying its claim to recover them (paragraph 6).	Addressed in section 8.1 of this application
Decision 21735-D02-2016 on AESO 2015 Deferral Account Reconciliation Interim Settlement	
Stakeholder consultation regarding DAR methodology and Rider C In its letter issued on September 19, 2016, the Commission determined that the issues raised by the PS Group had the potential to materially affect the current proceeding as well as past and future deferral account reconciliation proceedings. However, for the reasons set out in this decision, the Commission has approved the AESO's application and has not granted the relief requested by the PS Group. Nonetheless, the Commission expects the AESO to follow through on its commitment to further consult with stakeholders on this issue and directs the AESO to address whether changes to the deferral account allocation methodology and to Rider C are warranted given the concerns raised by the PS Group, as part of its next ISO tariff application (paragraph 108).	Addressed in section 6.1 of this application

10 Conclusion

402 Based on the entirety of the information provided with this application, the AESO requests approval of this application, including:

(a) approval of the bulk system, regional system, and point of delivery cost functionalization, the bulk system and regional system cost classification, and point of delivery cost function for 2018, 2019, and 2020 as presented in section 4 of this application;

(b) approval of the proposed amended 2018 ISO tariff in Appendix R to this application, including rates (except the monetary amounts), riders, terms and conditions, and appendices;

(c) confirmation from the Commission that the AESO's entire forecast revenue requirement is subject to deferral account treatment;

(d) confirmation from the Commission that the AESO has adequately responded to the Commission's outstanding directions; and

(e) such other relief as the Commission deems appropriate.

403 In the event that the Commission does not direct changes to the proposed rates and rider structures, the AESO requests that the 2018 ISO tariff be effective no earlier than the first day of the month at least 28 days after the date of the Commission's decision regarding the proposed 2018 ISO tariff to allow adequate time to implement the ISO tariff and to program and test the rates in the AESO's billing system. In the event that the Commission directs changes to the proposed rates and rider structures, then the AESO requests that the 2018 ISO tariff be effective no earlier than the first day of the month at least 58 days after the date of the Commission's decision regarding the AESO's compliance filing, to allow adequate time to implement the ISO tariff and to program and test the rates in the AESO's billing system.

All of which is respectfully submitted this 17th day of August, 2018

Alberta Electric System Operator

"Electronically submitted"

Per: Miranda Keating Erickson
Vice-President, Markets