Appendix F – Stakeholder Engagement Summary and Materials

1. Participant List

Stakeholders who participated in the consultation process in response to Decision 27047-D01-2022 and development of the AESO's revised plan to implement the adjusted metering practice ("AMP"), including and proposed amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17"), include representatives from the following entities:

- Alberta Direct Connect Consumers Association;
- AltaLink Management Ltd.;
- ATCO Electric Ltd.;
- Capital Power Corporation;
- City of Lethbridge (including Chymko Consulting Ltd.);
- City of Red Deer (including Chymko Consulting Ltd.);
- Power Advisory LLC. on behalf of The DCG Consortium;
- ENMAX Corporation;
- EPCOR Distribution and Transmission Inc.;
- FortisAlberta Inc.;
- Industrial Power Consumers Association of Alberta;
- Lionstooth Energy Inc.;
- University of Alberta;
- Utilities Consumer Advocate; and
- Versorium Energy Ltd.

2. Consultation Documents

Consultation documents that were posted on the AESO project-specific webpage for the Adjusted Metering Practice are listed below and have been included as attachments in this appendix.

Attachment	Description	Posting Date	PDF Page(s)
F.1	Post-Disposition Notice to Stakeholders	June 30, 2022	7
F.2	Update to Stakeholders	December 9, 2022	8
F.3a/b	Notice to Stakeholders	January 31, 2023 (updated March 2, 2023)	9 to 12
F.4	Continued Need, Benefit & Approach Consultation | March 6 – April 21, 2023		
F.4a	Section 1 | Background & Ongoing Need	March 6, 2023	13 to 28
F.4b	Section 2 | DCG Credits and the AMP	March 6, 2023	29 to 36
F.4c	Section 3 | Impact Analysis	March 6, 2023	37 to 48
F.4d	Section 4 | Moving Forward with the AMP	March 6, 2023	49 to 61

Attachment	Description	Posting Date	PDF Page(s)
F.4e	Section 5 | Totalized Billing	March 6, 2023	62 to 66
F.4f	Impact of BD Erosion on Billing	March 6, 2023	67 to 69
F.4g	Reversing PODs Discussion Paper	March 6, 2023	70 to 81
F.4h	Acronyms & Terms	March 6, 2023	82
F.5	Q&A Session | March 23, 2023		
F.5a	Presentation	March 23, 2023	83 to 94
F.5b	Q&A Board Stakeholder Questions	April 6, 2023	95 to 104
F.5c	Q&A Session & Question Board Summary and AESO Replies	April 6, 2023	105 to 132
F.5d	Q&A Supplemental Material	April 6, 2023	133 to 135
F.5e	Stakeholder Comments	April 24, 2023	136 to 162
F.5f	DCG Consortium Comments	April 24, 2023	163 to 167
F.5g	AML Comments	April 24, 2023	168 to 177
F.6	One on One Discussions | May 21 – August 15, 2023		
F.6a	AMP – Minimize or Eliminate Meter Costs	May 31, 2023	178 to 187
F.6b	Notice to Stakeholders	August 9, 2023	188
F.6c	Meeting Minutes | August 15, 2023	August 24, 2023	189 to 192
F.7	Written Consultation | July 21 – August 11, 2023		
F. 7a	Background and Update to Stakeholders	July 21, 2023 (updated July 24, 2023)	193 to 197
F.7b	Letter of Notice	July 21, 2023	198 to 200
F.7c	Stakeholder Comment Matrix	July 21, 2023	201 to 202
F.7d	ISO Tariff Blackline	July 21, 2023 (updated July 24, 2023)	203 to 226
F.7e	Section 503.17 Blackline	July 21, 2023	227 to 230
F.7f	Section 503.17 Clean	July 21, 2023	231 to 234
F.7g	Stakeholder Comments on Letter of Notice • AltaLink Management Ltd. • Cities of Red Deer and Lethbridge • DCG Consortium • ENMAX Corporation • EPCOR Distribution & Transmission Inc. • Industrial Power Consumer Association of Alberta • Versorium Energy Ltd.	August 17, 2023	235 to 255

Attachment	Description	Posting Date	PDF Page(s)
F.7h	AESO Response Letter	August 25, 2023	256
F.7i	Stakeholder Comments and AESO Replies Matrix	August 25, 2023	257 to 273

3. Summary of Stakeholder Engagement Subsequent AUC Decision 27047-D01-2022

Following issuance of AUC Decision 27047-D01-2022, the AESO engaged with stakeholders with a view to developing a revised AMP implementation plan. Key stakeholder engagement steps consisted of the following:

- **June 30, 2022** – the AESO issued a post-disposition notice to Stakeholders, with a copy filed in Proceeding 27047, to clarify that the phase-out of DCG credits has limited bearing upon the benefit that would be achieved through AMP implementation and, further, that there continues to be a benefit from implementing the AMP because artificial billing determinant erosion continues to occur at DFO point of connection substations even with the phase out of DCG credits. The notice describes the AESO's intention to develop and re-file a revised AMP implementation plan.
- **January 31, 2023** – the AESO posted a Notice to Stakeholders regarding the AESO's plans for additional stakeholder engagement on the AMP. The AESO stated that prior to filing another AMP application, the AESO would be engaging with stakeholders regarding the continued need and benefit of the AMP and potential approaches to implementing the AMP in light of AUC Decision 27047-D01-2022.
- **March 6, 2023** – the AESO posted engagement materials on the AESO Engage platform to seek feedback from interested stakeholders on their perspectives as it relates to the continued need and benefit of the AMP and potential approaches to implementing the AMP in light of AUC Decision 27047-D01-2022. The AESO requested that stakeholders post questions on the AESO Engage Question Board if the AESO's engagement materials were confusing or unclear and required further clarification.
- **March 23, 2023** – the AESO hosted a virtual Q & A Stakeholder session to respond to questions posted on the AESO Engage Question Board and to provide an opportunity for stakeholders to discuss any further questions or concerns that they may have and to explore any areas where clarification is still required on the AMP.
- **April 21, 2023** – Stakeholders provided feedback on the engagement materials posted. Some stakeholders supported the AMP, while others did not. Cost was identified as a primary stakeholder concern.
- **May 31, 2023** – the AESO posted a presentation titled "AMP – Minimize or Eliminate Meter Costs" that would be used to guide one on one discussions with stakeholders. Over the course of May and June 2023, the AESO held one-to-one meetings with stakeholders that had previously provided feedback on the AMP, to better understand stakeholder concerns and to explore potential approaches to AMP implementation that could address concerns about costs. The presentation and these discussions included the approaches described in Appendix A – AMP Alternatives Comparison. Specifically, the AESO held one-to-one meetings with representatives from the following stakeholders:
    - Alberta Direct Connect Consumer Association (ADC)
    - AltaLink Management Ltd.
    - ATCO Electric Ltd.
    - Capital Power Corporation
    - ENMAX Corporation

- EPCOR Distribution & Transmission Inc.
- FortisAlberta Inc.
- Lionstooth Energy
- The City of Lethbridge (including Chymko Consulting Ltd.)
- The City of Red Deer (including Chymko Consulting Ltd.)
- Power Advisory LLC. on behalf of The DCG Consortium
- The Industrial Power Consumers Association of Alberta (IPCAA)
- The University of Alberta (including Chymko Consulting Ltd.)
- The Utilities Consumer Advocate
- Verisorium Energy Ltd.

The AESO encouraged other interested stakeholders to contact the AESO if they wished to discuss the AMP with the AESO. However, no other stakeholders contacted the AESO.

- Issues discussed at the above-described one-on-one discussions with stakeholders included the following:
  - Legacy Treatment, which would exempt certain DFO substations (and therefore the SAS, and market participants at those substations) from complying with AMP provisions in the ISO tariff
  - Resulting differential treatment and fairness concerns, including preliminary numbers
  - The impact of the AMP on DTS and STS contract capacities, and whether DFOs would adjust DTS contract capacity, how STS contract capacity is currently determined
  - Whether DFOs are considering system access service (SAS) contracting by feeder / groups of feeders / by substations
  - Ability of DFOs to manage flows to prevent reversals
  - How/when the work to change out metering to comply with the AMP could occur
  - Whether feeder level metering at all DFO substations should be an ISO rule requirement; the cost of and who should pay for meter installations; the incremental work required to prepare substation infrastructure for feeder level metering when coupled with other major alterations; and the age of equipment at existing DFO substations
  - DCG size and connection limitations (for ex. dedicated feeders, # of DCG on a feeder); DCG locational signals – space requirements, noise limitations, land costs; the types and amounts of DCG connection requests in DFO service areas
  - Discussions with DFOs to better understand DCG credit calculation and credit data; DCG credit phase-out in relation to the timing of the AMP
  - The impact of the AMP on Rate STS, and flow-through to DCG
  - Loss factors and the AMP
  - AMP timing and implications in relation to a potential new Rate DTS design
  - Impact of the AMP on DFO non-wires alternatives
  - The AMP and source asset aggregation in the energy market
  - The AESO's proposed totalized billing revisions

- **July 21, 2023** – in response to stakeholder feedback, the AESO posted an Update to Stakeholders in which it advised that it had decided in its upcoming AMP application to propose an AMP implementation plan as follows:

  (i) Upon the AMP becoming effective (i.e., approved for implementation by the Alberta Utilities Commission (Commission), for all existing substations that connect to an electric distribution system (DFO Substations) with reversing flows and revenue meters at the feeder level, administrative actions would be taken by the AESO to implement the AMP. This administrative work would consist of updating Measurement Point Definition Records, data systems, and SAS agreements to align with the AMP.

  (ii) However, for existing DFO Substations that have reversing flows but do not already have revenue meters at the feeder level, exemptions would be provided. In other words, these DFO Substations will not be required to immediately comply with the AMP.

  (iii) New revenue metering requirements would be incorporated into Section 503.17 of the ISO Rules, *Revenue Metering System* (Section 503.17), to require:

    a. For new DFO Substations, at a minimum, infrastructure capable of feeder level metering so that revenue meters can be easily installed if and when there are reversing flows.

    b. For existing DFO Substations that currently have revenue meters at the transformer level, the installation of either the infrastructure capable of feeder level metering or the complete revenue metering system at the feeder level installed at such time as the substation is required to undergo significant lifecycle alterations or rebuilds. At that point, the incremental cost of installing a revenue meter system at the feeder level would be negligible since the substantive work and costs associated with retrofitting the substation would be occurring for the lifecycle alteration or rebuild anyway.

  (iv) Section 3 of the ISO tariff would be revised to require contract capacities for new or modified SAS in a manner to align with the AESO's AMP proposed approach; i.e., to require AMP compliant contract capacities, except at DFO Substations where an exemption has been provided.

    a. If a market participant is requesting new or amended SAS at a DFO Substation that already has a revenue metering system at the feeder level, or at least has the infrastructure capable of feeder level metering, then new or amended SAS can be contracted, measured, and billed in a manner compliant with the AMP.

    b. If a market participant is requesting new or amended SAS at a DFO Substation that only has transformer level metering, and there are reversing flows at the substation, then SAS cannot be measured and billed in a manner compliant with the AMP since the revenue meters cannot easily be installed at the feeder level. In these circumstances, the ISO tariff would permit SAS to be contracted in a manner that does not align with the AMP.

- **July 21, 2023** – in accordance with AUC Rule 017, the AESO posted a Notice for Development which sought feedback on the proposed amendments to Section 503.17 of the ISO rules that the AESO considered to be required to implement the AMP. The AESO also sought Stakeholder feedback on the AESO's proposed approach to AMP implementation. In response, written comments were received from the following Stakeholders:
  - AltaLink Management Ltd.;
  - Cities of Red Deer and Lethbridge;

- DCG Consortium;
- ENMAX Corporation;
- EPCOR Distribution & Transmission Inc.;
- IPCAA;
- Office of the Utilities Consumer Advocate; and
- Versorium Energy Ltd.

As set out in the written feedback included in this appendix, EPCOR, ENMAX, IPCAA, and the UCA supported the AESO's proposed approach to AMP implementation, while Altalink, The Cities of Red Deer and Lethbridge, the DCG Consortium, and Versorium Energy expressed opposition to the proposed approach to AMP implementation and/or the AMP generally.

- **August 15, 2023** – the AESO held a technical meeting with AUC staff to present the AMP implementation alternatives that were discussed with stakeholders and to respond to clarifying questions from AUC staff. No new information was presented beyond that which had previously been included in the AESO's stakeholder sessions. Minutes from the technical meeting were posted to AESO Engage on August 24, 2023 and have been included as part of the consultation record in this application.
- **August 25, 2023** – the AESO posted replies to Stakeholder Comments received.

Notice

To: Market Participants and Other Interested Parties (Stakeholders)

Date: June 30, 2022

Subject: **Post-Disposition Notice – Proposed Adjusted Metering Practice (AMP) Implementation and Proposed Amendments to Section 502.10 of the ISO Rules, *Revenue Metering System Technical and Operating Requirements* (Section 502.10)**

The Alberta Electric System Operator (AESO) provides the following to stakeholders to provide clarity regarding next steps following the issuance of Commission Decision 27047-D01-2022 (Decision) on May 31, 2022, in which the Commission denied the AESO's application for approval to implement the AESO's AMP at substations that connect to electric distribution systems (DFO Substations).

Background

On May 31, 2022, the Commission issued the Decision in which the Commission denied the AESO's application for approval of the proposed AMP implementation plan, including proposed amended Section 502.10 of the ISO rules and related ISO tariff amendments. In its decision the Commission stated:

- that it was unclear how much benefit can be achieved through AMP implementation, given that the phase out of DCG credits will eliminate one of the major causes of billing determinant erosion;
- that the AESO was not required to file a further application proposing an implementation plan; and
- that, should the AESO choose to file such an application, the AESO should include improved cost estimates in support of that implementation plan (AACE Class 3 and 5), along with a cost-benefit analysis.

Next Steps regarding the AMP

- The AESO wishes to clarify to stakeholders that the DCG credits themselves do not cause billing determinant erosion, and therefore that the phase-out of DCG credits only has a limited bearing on the benefit that would be achieved through implementation of the AMP. Without the AMP in place, current billing determinants are resulting in an estimated cross subsidy of up to $30M per year to DFOs from other users of the transmission system (billing determinant erosion). This billing determinant erosion occurs regardless of the phase-out of DCG credits and will continue to grow over time as more DCG connects to the grid. Therefore, it is the AESO's intention to re-file an AMP implementation plan before the end of 2022.
- The AESO requires certain information from the TFOs and DFOs to perform the cost benefit analysis described in the Decision. The AESO also intends to discuss with TFOs the feasibility of the cost estimating requirements set out in the Decision, which may be unduly onerous or costly to obtain.
- Following the collection of the information described above, the AESO intends to move forward with a new application for approval to implement the AMP.
- In the meantime, new and in-flight DFO connection projects are to continue with the practices for determining STS capacity and for requiring feeder meter installation that were in place without the AMP.

Questions regarding the above may be directed to **stakeholder.relations@aeso.ca**

Alberta Electric System Operator
www.aeso.ca
Calgary Place, 2500, 330-5th Avenue SW Calgary, AB T2P 0L4
Phone: 403-539-2450 | Fax: 403-539-2949

Notice

To: Market Participants and Other Interested Parties

Date: December 9, 2022

Subject: **Update to Stakeholders regarding the AESO's Proposed Adjusted Metering Practice (AMP)**

The Alberta Electric System Operator (AESO) is providing the following update to stakeholders regarding the AMP.

On May 31, 2022, the Commission issued Decision 27047-D01-2022, denying the AESO's application for approval to implement the AMP. On June 30, 2022, the AESO posted on its website and filed in AUC Proceeding 27047 a post-disposition letter indicating that:

- Regardless of the phase-out of DCG Credits, there continues to be a benefit associated with implementing the AMP; and
- The AESO consequently intends to re-file an AMP implementation plan before the end of 2022.

The AESO can now advise that the AESO will not be re-filing an AMP implementation plan before the end of 2022. Instead, the AESO intends to file a further application regarding the AMP on or before March 31, 2023.

Prior to the March 2023 filing, the AESO intends to provide stakeholders with additional information in support of the AESO's views about the continued benefit of the AMP, as well as potential options for moving forward with the AMP in light of Decision 27047-D01-2022. The AESO will provide stakeholders with details regarding this upcoming stakeholder engagement process in January 2023.

Questions regarding the above may be directed to Tariffdesign@aeso.ca.

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Notice

To: Market Participants and Other Interested Parties (Stakeholders)

Date: January 31, 2023

Subject: **Stakeholder Engagement Regarding the AESO's Proposed Adjusted Metering Practice (AMP)**

On December 9, 2022, the Alberta Electric System Operator (AESO) posted a Notice to Stakeholders on www.aeso.ca regarding the AESO's plans for additional stakeholder engagement on the AMP.

The AESO is writing to provide Stakeholders with additional details regarding its upcoming stakeholder engagement on the AMP.

Objectives of the Stakeholder Engagement

In the AESO's December 9th, 2023 update letter, the AESO stated that it anticipates filing a new application regarding the AMP before the end of Q1 2023. The AESO now intends to file this application shortly after the end of Q1, in April 2023.

Prior to the filing of this application, the AESO intends to engage with Stakeholders regarding the continued need for and benefit of the AMP and the AESO's proposed path forward in light of Alberta Utilities Commission (AUC) Decision 27047-D01-2022.

The AESO intends to present to Stakeholders on the following:

1) The continued need to implement the AMP, in order to provide for billing at substations that connect to electric distribution systems, in a manner that reflects how the transmission system is used; and
2) How the approved phase-out of Distribution Connected Generation (DCG) credits does not eliminate the need for and benefit that will be provided through implementation of the AMP.

The AESO also intends to engage with Stakeholders on the options that the AESO is considering to implement the AMP as a result of AUC Decision 27047-D01-2022.

The AESO will also address proposed ISO tariff revisions to enable billing totalization where the same service is provided to a market participant at a substation.

AESO Engage platform

On Sept. 22, 2022, the AESO launched a new external engagement platform entitled "AESO Engage". The AESO intends to use the AESO Engage platform for this engagement. Following the publication of written materials, the AESO will provide Stakeholders with an opportunity to provide written questions and feedback, through the AESO Engage platform, for the purpose of addressing areas of confusion and identifying Stakeholder concerns.

Following the written consultation, the AESO also intends to hold a hybrid "Q&A" session to discuss any further questions or concerns that Stakeholders may have and to explore any areas where clarification is still required. Depending on the nature of the written feedback that is received, the AESO may also post written responses to Stakeholder feedback and/or develop a frequently asked questions (FAQ) document to provide more detailed responses to questions or concerns that Stakeholders raise.

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Stakeholders can view all engagements and any materials and links featured on AESO Engage without registering or signing in. If Stakeholders wish to actively participate on AESO Engage, for example by submitting written feedback, registration on AESO Engage will be required and the feedback will be attributable to the organization that provided it.

A link to the AESO Engage site for the AMP stakeholder engagement will be provided no later than March 2, 2023 and will be accessible via the AESO website (www.aeso.ca) and follow the path: AESO Engage (top navigation bar) > Adjusted Metering Practice.

AMP Stakeholder Engagement Schedule

Target Date	Consultation Step
March 2, 2023	Post engagement materials on the AESO Engage platform and provide Stakeholders with an opportunity to submit written questions and comments
March 16, 2023	Deadline for the submission of written Stakeholder feedback
March 23, 2023	Hybrid Q&A Session
April 14, 2023	Targeted date to file Application

Questions regarding the above may be directed to tariffdesign@aeso.ca.

To: Market Participants and Other Interested Parties (Stakeholders)

Date: January 31, 2023 [Updated: March 1, 2023]

Subject: **Stakeholder Engagement Regarding the AESO's Proposed Adjusted Metering Practice (AMP)**

On December 9, 2022, the Alberta Electric System Operator (AESO) posted a Notice to Stakeholders on www.aeso.ca regarding the AESO's plans for additional stakeholder engagement on the AMP.

The AESO is writing to provide Stakeholders with additional details regarding its upcoming stakeholder engagement on the AMP.

Objectives of the Stakeholder Engagement

In the AESO's December 9th, 2023 update letter, the AESO stated that it anticipates filing a new application regarding the AMP before the end of Q1 2023. The AESO now intends to file this application shortly after the end of Q1, in April 2023.

Prior to the filing of this application, the AESO intends to engage with Stakeholders regarding the continued need for and benefit of the AMP and the AESO's proposed path forward in light of Alberta Utilities Commission (AUC) Decision 27047-D01-2022.

The AESO intends to present to Stakeholders on the following:

1) The continued need to implement the AMP, in order to provide for billing at substations that connect to electric distribution systems, in a manner that reflects how the transmission system is used; and
2) How the approved phase-out of Distribution Connected Generation (DCG) credits does not eliminate the need for and benefit that will be provided through implementation of the AMP.

The AESO also intends to engage with Stakeholders on the options that the AESO is considering to implement the AMP as a result of AUC Decision 27047-D01-2022.

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A link to the AESO Engage site for the AMP stakeholder engagement will be provided no later than March 6, 2023 and will be accessible via the AESO website (www.aeso.ca) and follow the path: AESO Engage (top navigation bar) > Adjusted Metering Practice.

AMP Stakeholder Engagement Schedule

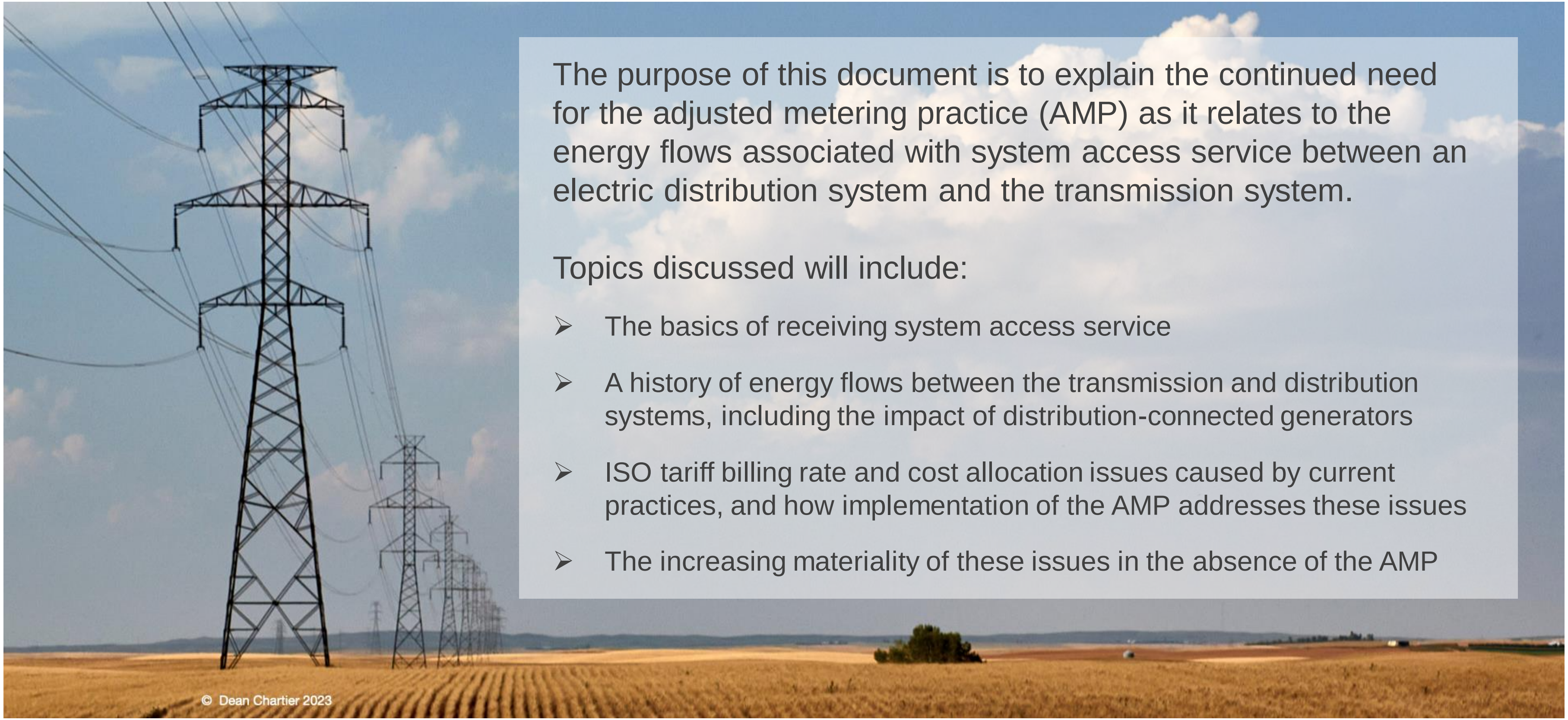
Target Date	Consultation Step
March 6, 2023 – updated	Post engagement materials on the AESO Engage platform and provide Stakeholders with an opportunity to submit written questions and comments
March 20, 2023 – updated	Deadline for the submission of written Stakeholder feedback
March 23, 2023	Hybrid Q&A Session
April 14, 2023	Targeted date to file Application

Questions regarding the above may be directed to tariffdesign@aeso.ca.

AMP Engagement

Background & Ongoing Need

Introduction

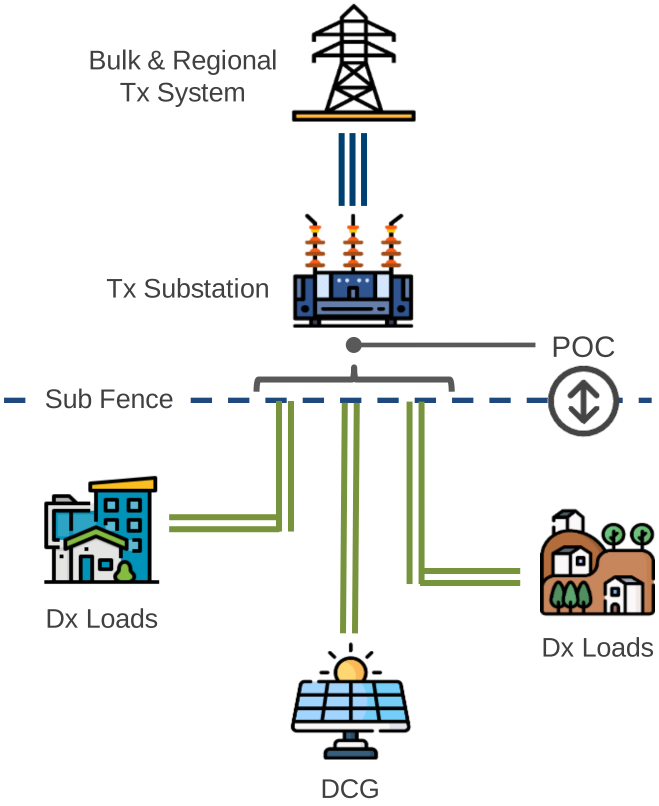


The purpose of this document is to explain the continued need for the adjusted metering practice (AMP) as it relates to the energy flows associated with system access service between an electric distribution system and the transmission system.

Topics discussed will include:

- The basics of receiving system access service
- A history of energy flows between the transmission and distribution systems, including the impact of distribution-connected generators
- ISO tariff billing rate and cost allocation issues caused by current practices, and how implementation of the AMP addresses these issues
- The increasing materiality of these issues in the absence of the AMP

Basics of System Access Service



MPs wishing to exchange electricity with the transmission system must enter into an agreement with the AESO to obtain SAS under the appropriate rate:

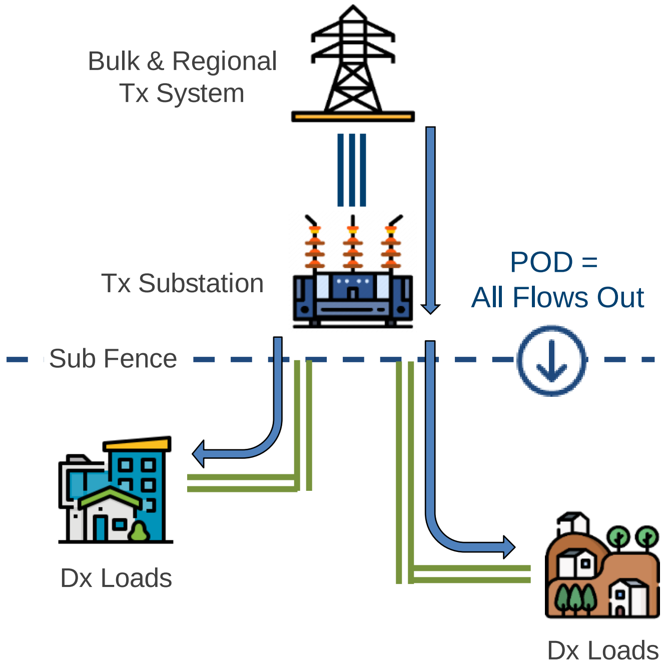
- Rate DTS – for receiving electricity from the transmission system
- Rate STS – for supplying electricity to the transmission system

SAS is provided at the POC between the transmission system and the MP facilities. The POC is a conceptual point where all energy is deemed to be exchanged for the purposes of energy measurement and ISO tariff billing of the SAS agreement. The POC may be either a POD for rate DTS, a POS for rate STS, or both if rate DTS *and* rate STS are being provided.

For distribution systems, the POC is the demarcation point between transmission and distribution (the fence of the transmission substation where the distribution feeders enter). As a distribution system has multiple feeders connecting to the substation, the POC represents the energy exchanged across all of the feeders.

To learn more about rate DTS and rate STS and how the ISO tariff is billed, see the ISO Tariff Billing course on the AESO's Continuing Education website.

Load-Only Beginnings of Distribution Systems

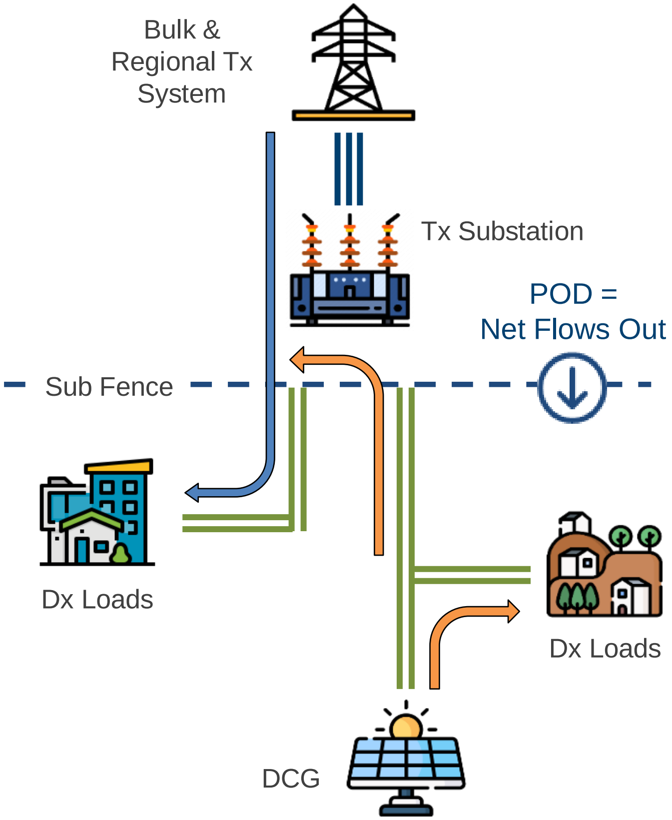


In the early years of deregulation, connections between the transmission system and distribution system were typically one-way flows of energy supplied from the bulk and regional transmission system through the transmission substation to feed the loads on the distribution system.

DFOs contracted with the AESO for SAS at the POD under rate DTS and were issued ISO tariff bills under that rate.

While the AESO's measurement practice at the time technically netted all of the energy flows on the feeders connected to the substation, it had no impact on the results with all of the energy flowing in the same direction. The measurement data for the POD represented all of the energy delivered to the DFO from the transmission system.

Distribution-Connected Generators



While there was some initial DCG installed, they were few in number with relatively low generation volumes. Most of the energy produced by a DCG was used by distribution loads connected to the same feeder.

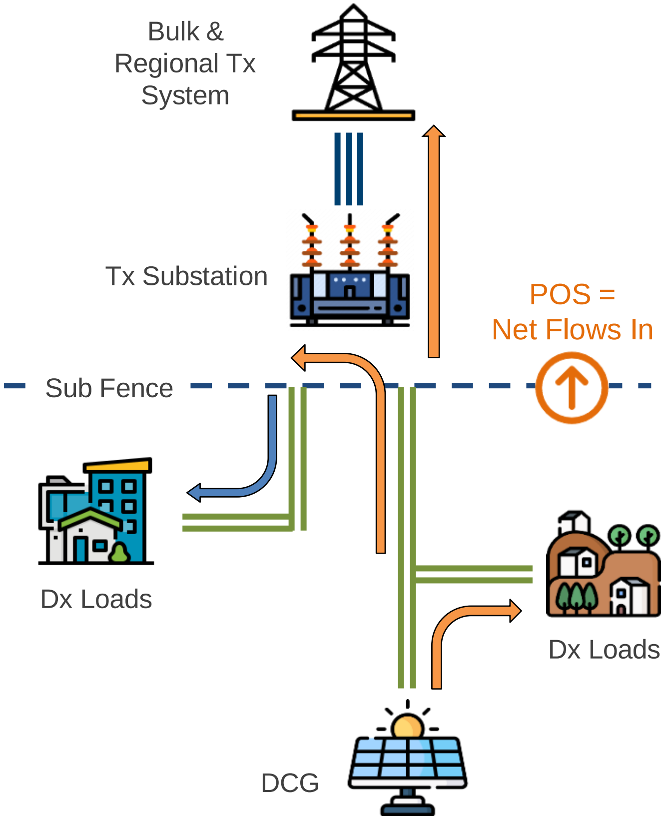
If any generation did supply all loads on the feeder and “reverse” back into the transmission substation, it supplemented the energy flows coming from the bulk and regional transmission system to supply the distribution loads on the other feeders connected to the substation.

The measurement practice netted the reversing flow from the other energy flows leaving the substation, resulting in a net outflow. This slightly under-represented the total energy received by the DFO at the POD but avoided requiring a POS for the energy flowing into the substation, a practice not yet in place for distribution systems.

These reversing flows were low in volume and uncommon, and not considered material enough to change the netting practice.

Some DFOs also introduced a “DCG Credit” at this time to reflect the loads offset by DCG. See the **DCG Credits and the AMP** material for more information.

Appearance of Reversing PODs



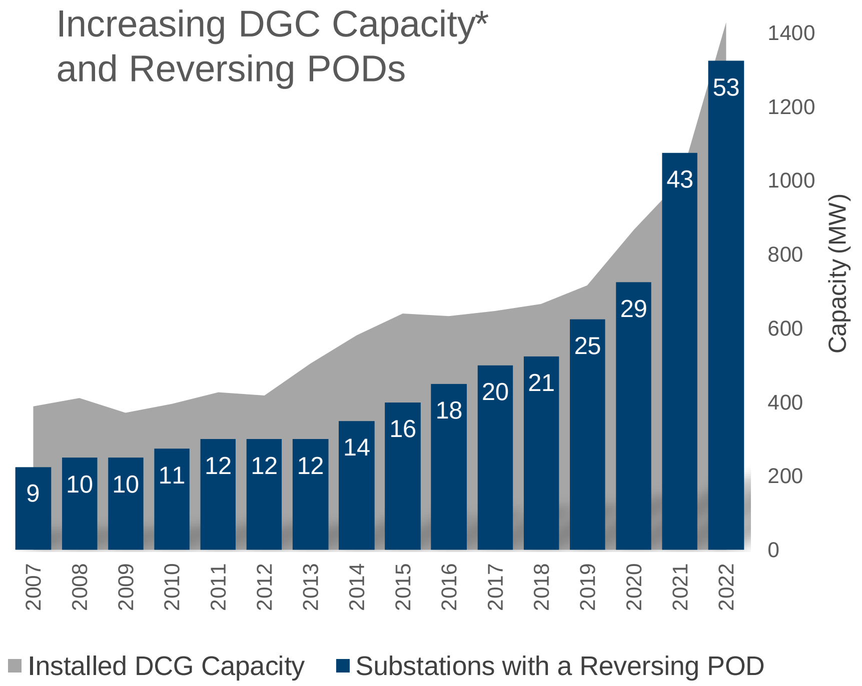
By 2007 DCG production had grown to the point where it was possible to supply all the distribution loads at a substation and “reverse” the POD into a POS; excess inflows from the distribution system were now flowing through the substation to the bulk and regional transmission system.

This posed a problem, as DFOs had not previously needed to obtain SAS under rate STS to supply energy, and data systems were not set up to account for these flows. These flows were therefore included as unaccounted for energy (UFE) on the distribution system.

To address this settlement issue, the AUC (then EUB) introduced a new measurement type for this “excess” distributed generation (EDG). DFOs contracted for SAS under rate STS for the POS and were issued ISO tariff bills under that rate. See the **Reversing PODs Discussion Paper**, which was issued by the AESO in 2007 for stakeholder discussion purposes, for more information.

As a result of the new measurement type exchanged energy was now correctly settled, but the netting of flows continued to under-represent the actual energy received by the DFO at the POD (and now, the energy supplied by the DFO at the POS as well). However, these reversals were still not considered material enough to change the netting practice.

The Current Situation



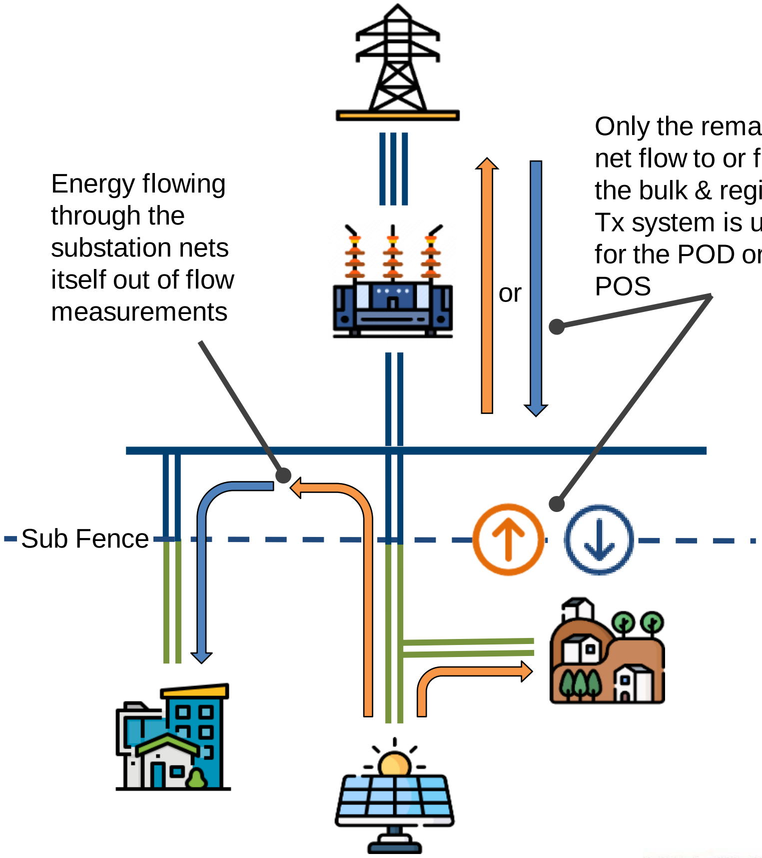
*Includes all interval metered DCG and large micro-generation

In the years since the introduction of reversing PODs and EDG data, installed DCG capacity has increased by over 250 per cent, and the number of substations with a reversing POD has increased almost 500 per cent from nine to 53. This rate of growth suggests that energy reversing into substations from the distribution system is no longer low in volume or uncommon.

The measurement practice for assessing flows for the POC has not changed and the energy exchanged between the transmission system and distribution system continues to be netted, with the result attributed to either the POD or POS as appropriate.

The under-representation of the actual energy flows occurring under each type of SAS now has material impacts on ISO tariff billing which must now be addressed.

How Netting Under-Represents Transmission System Usage



While netting all of the flows entering and leaving a substation accurately represents the overall exchange of energy between the transmission and distribution systems, it does not reflect how the transmission system is actually being used by the DFO to supply and receive energy.

A distribution system is connected to a transmission substation through multiple feeders. When the energy from a DCG has supplied all loads on its own feeder, the remainder will flow into the substation and across the bus to supply distribution loads on other feeders. This energy flow through the substation cancels itself out in the netting process.

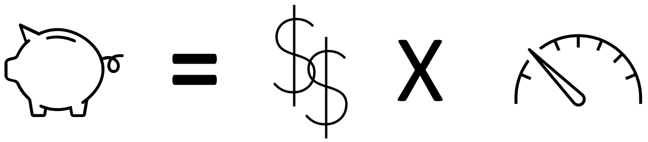
The result is that the POD represents less energy than is actually being received by the DFO from the transmission system, and the POS represents less energy than is actually being supplied by the DFO to the transmission system. This under-representation carries through when the POD and POS are used as inputs in the ISO tariff billing determinants.

The DFO is in effect using the transmission system to supply their own loads, without that flow being measured and accounted for in the ISO tariff billing process.

Impacts on ISO Tariff Billing

The impact of netting energy flows is that the billing determinants used for ISO tariff billing understate the actual energy delivered, artificially “eroding” the pool of billing determinants and leading to higher rates for MPs and misallocations of recovered costs.

The AESO must recover the costs to provide SAS to MPs. These costs are recovered by applying the rates (the cost per unit) to the energy flow billing determinants and issuing ISO tariff bills to MPs. To learn more about billing determinants and how the ISO tariff is billed, see the ISO Tariff Billing course on the AESO’s Continuing Education website.



As the costs the AESO must recover are fixed, if the pool of billing determinants goes down because of the artificial erosion caused by the netting of energy flows, the overall rate must inherently increase for all MPs.

MPs with billing determinants based on actual energy flows bear an over-allocation of the costs of service because of the higher rates. Conversely, DFOs with netted energy flows benefit from an under-allocated amount due to their lower billing determinants. Overall, this results is a misallocation of the recovered costs among MPs.

To walk through an illustrative example of billing determinant erosion, see the **Impact of BD Erosion on Billing Example**.

Other Impacts Caused by Netting

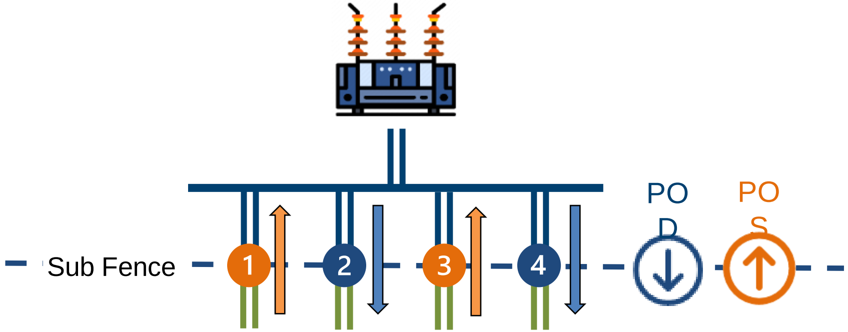
While the erosion of billing determinants is the primary consequence of the netting of energy flows, there are a number of other negative consequences that have resulted from this practice, some of which have been addressed through other changes.

GUOC	GUOC was previously calculated based on capacity contracted under rate STS, meaning that so long as inflows from the distribution system didn't cause a reversing POD, a GUOC was not required to be paid. If a reversing POD did exist, the contracted capacity only represented the overall net inflow, and did not reflect the size of the DCG. This was addressed when the calculation was changed to be based on the generator maximum capability in AUC Decision 22942-D02-2019.
SSF	The amount of local investment at a substation was previously based on the ratio of contracted capacities for SAS at the substation. The netting practice meant that at many substations with energy inflows the DFO either didn't require SAS under rate STS or had very low contract capacities for that SAS. This resulted in "supply" not bearing their share of the costs of using the substation. This was addressed by the AESO's SSF=1 proposal, approved in AUC Decision 25848-D01-2020.
Loss Factors	Loss factors are associated with the POS for SAS provided under rate STS. Any substations with energy inflows but without SAS under rate STS because of the netting practice are not assigned any loss factors and are not included in the loss factors process. Substations that do have an STS and loss factors assigned end up being allocated an improper dollar amount for losses because of the low POS flows for the STS.

Addressing Billing Determinant Erosion with the AMP

To address the artificial erosion of billing determinants the measurement practice of netting flows must change to one that aggregates energy into the POD or POS individually based on the direction of flow across the border between the transmission and distribution systems. This individual aggregation practice is the AMP.

Under the AMP, the overall exchange of energy stays the same, but the POD and POS would now reflect the actual energy being delivered to or supplied by the DFO. Consequently, billing determinants would reflect the actual use of transmission facilities by the DFO, and MPs would be charged for their correct share of recovered costs.



Current Measurement Practice (Net)

$$\left.\begin{aligned} \downarrow &= (2 + 4) - (1 + 3) \\ \uparrow &= (1 + 3) - (2 + 4) \end{aligned}\right\} \text{Zero if} < 0$$

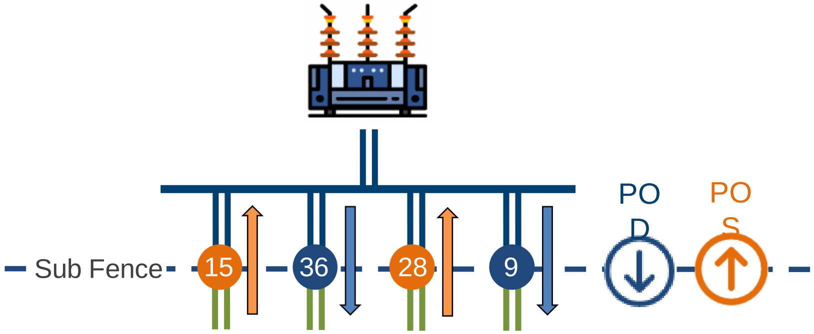
Energy flows on each feeder are netted and associated with either the POD (for a net outflow) or the POS (for a net inflow). Data does not reflect the energy flows *through* the transmission system, eroding the billing determinants.

Adjusted Measurement Practice (Individual)

$$\downarrow = 2 + 4 \qquad \uparrow = 1 + 3$$

Feeders with energy outflows are aggregated to the POD, and feeders with energy inflows are aggregated to the POS. Data reflects the full use of the transmission system and billing determinants remain whole.

The Practice in Practice



Current Measurement Practice (Net)

POD = (36 + 9) – (15 + 28) = 2 MWh

POS = (15 + 28) – (36 + 9) = –2 MWh = 0

Adjusted Measurement Practice (Individual)

POD = 36 + 9 = 45 MWh

POS = 15 + 28 = 43 MWh

In the example on the left, two of the feeders are supplying a total of 43 MWh of energy into the transmission system, and two are receiving a total of 45 MWh of energy from the transmission system.

Under the current measurement practice, the 43 MWh of supplied energy is netted against the 45 MWh of received energy. The net result of 2 MWh received goes into the POD data for use in the rate DTS billing determinants, and the POS is zero.

Under the AMP, all 43 MWh of supplied energy goes into the POS data for use in the rate STS billing determinants, and all 45 MWh of received energy goes into the POD data for use in the rate DTS billing determinants.

Under the current practice the 43 MWh of energy flowing *through* the substation is not associated with either the POD or POS data, eroding the billing determinants for both rate DTS and rate STS and causing increased rates and cost misallocations.

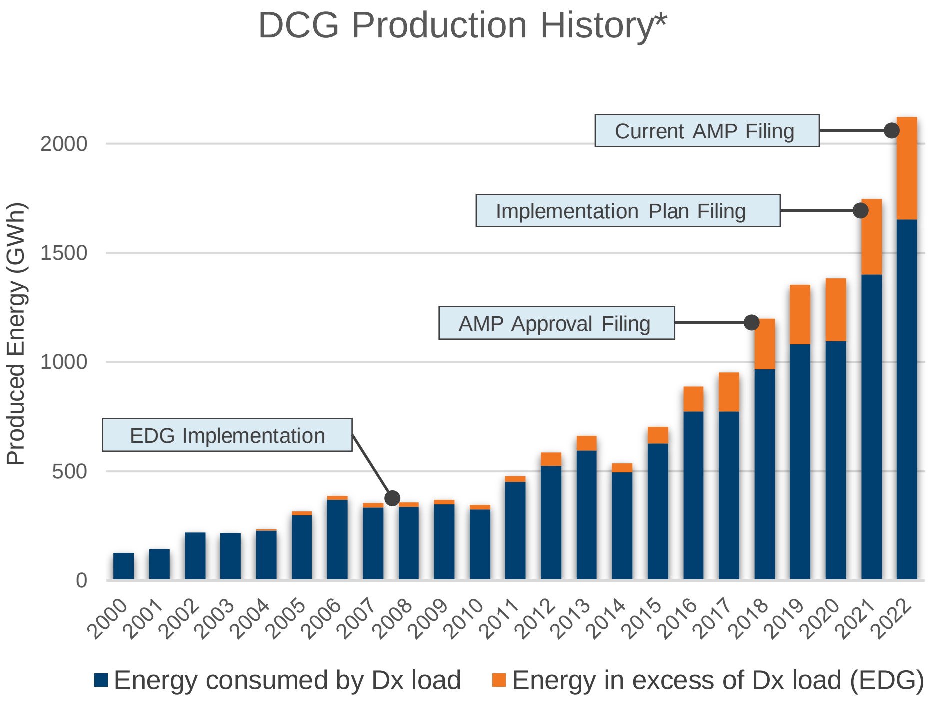
Under the AMP, actual flows in each direction are fully reflected in the POD and POS data, and the billing determinants remain whole.

Requirements to Implement the AMP

A number of changes are needed to move from the current measurement practice to the AMP. These changes may be physical in nature at the transmission substation, or administrative in nature in data systems, records, and agreements. For more information on the overall scope and cost of implementing the AMP see the **Moving Forward With the AMP** material.

Physical Changes	For substations with reversing flows, the core requirement to implement the AMP is the ability to meter the energy flows of the individual feeder connections. This was not a requirement for the current practice, as a transformer-level meter inherently nets energy flows. A transmission substation that currently has transformer metering (typically the substations in urban locations) must convert to feeder metering to properly aggregate the flows under the AMP. The changes required depend on the individual substation and could vary in scope considerably.
Administrative Changes	For substations with reversing flows, if there is feeder metering in place (or once it has been converted to feeder metering), the MPDR that describes the specific energy flow aggregations at the substation must be updated to reflect the AMP, and MDMs must configure their measurement data systems for any new meters and changes to measurement data aggregations. Additionally, SAS agreements must be either executed (for new reversing PODs) or amended (for existing agreements requiring capacity changes) to reflect the measured flows under the AMP. Any new reversing PODs would need a MPDR created, and the MDM would need to update their system.
No Changes	Substations without any reversing flows on the feeders do not require any physical or administrative changes as there is no effective difference between the AMP and the current measurement practice.

Why Implement the AMP Now?



*Includes all interval metered DCG and large micro-generation

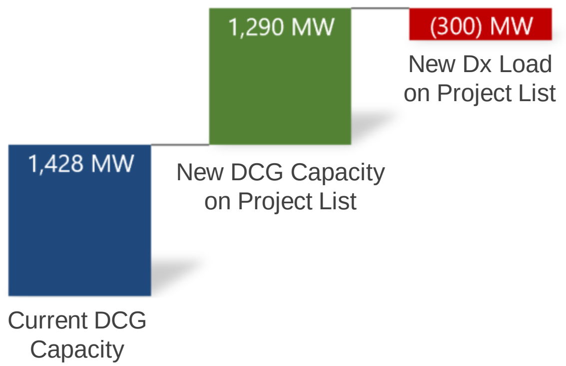
DCG production started modestly and held steady for a number of years until 2011, when production started to increase and has since risen over 400 per cent. This production can be split into two categories:

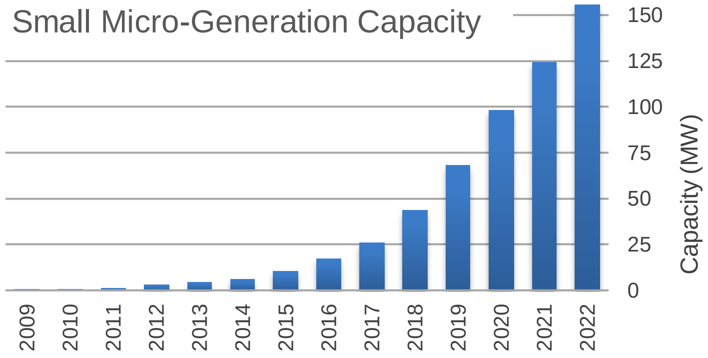
- Energy in excess of distribution load served at the substation (captured by the EDG data type for reversing PODs)
- “Consumed energy”, which is the remaining amount of produced energy inherently consumed by distribution load

With the current netted measurement data, the volume of consumed energy flowing through the transmission substation (rather than being consumed by loads on the same feeder) cannot be determined. However, the increase in both excess and consumed energy indicates that the billing determinant erosion has kept pace with the DCG production increases.

See the **Impact Analysis** AMP material for a breakdown of the impacts of erosion and the benefits that would be seen by implementing the AMP for 2021.

Increasing Erosion in the Absence of the AMP





Based on the AESO's project list, the artificial erosion of billing determinants caused by the netting practice will increase for the foreseeable future. There is currently enough DCG capacity in the project list to almost double installed capacity, with little new distribution load to consume it.

Micro-generation continues to grow under the Micro-generation Regulation, and newer regulations like the Small Scale Generation Regulation are designed to incent additional growth.

The AUC's approved phase-out of the DCG credits may suppress the rate of new DCG growth, but this will not eliminate the expected growth nor address any existing erosion. See the "DCG Credits and the AMP" material for more information on this relationship.

The rate that new DCG is added to the distribution system will ebb and flow as various incentives come and go and market conditions change, but generation will continue to increase.

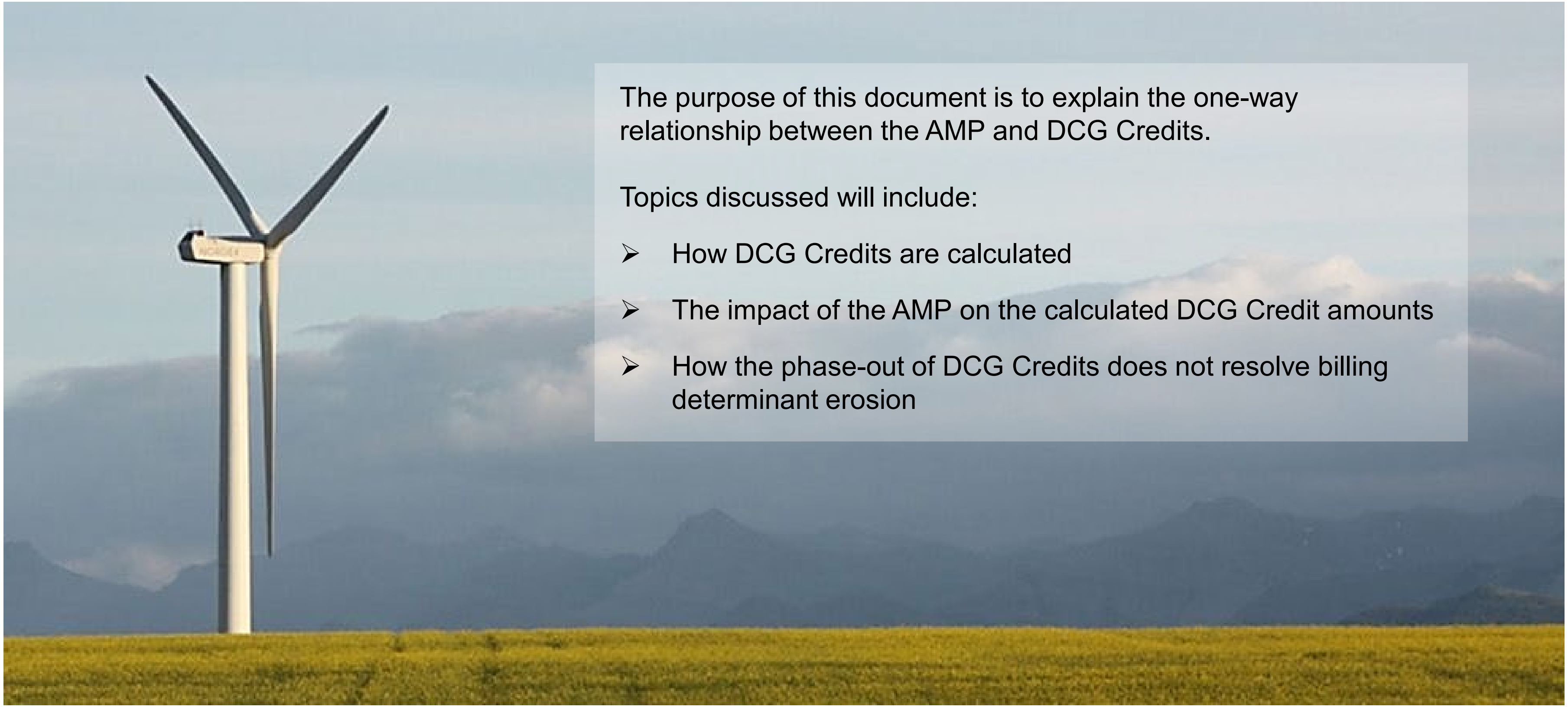
Unless the AMP is implemented the erosion of billing determinants and resulting increases ISO tariff billing rates and related misallocation of costs for MPs will continue to increase as well.

Have questions? Please add them to the “Question Board” on the AMP AESO Engage page

AMP Engagement

DCG Credits and the AMP

Introduction



The purpose of this document is to explain the one-way relationship between the AMP and DCG Credits.

Topics discussed will include:

- How DCG Credits are calculated
- The impact of the AMP on the calculated DCG Credit amounts
- How the phase-out of DCG Credits does not resolve billing determinant erosion

Commission Findings Regarding DCG Credits

- In AUC Decision 26090-D01-2021:
  - The Commission described DCG Credits as the payments that ATCO Electric, ENMAX and Fortis provide to DCG (both without associated load and as part of self-supply and export configurations) connected to their respective distribution systems. These credits are calculated and paid pursuant to provisions within their respective tariffs: Option M for Fortis, Rate D32 for ATCO Electric, and Rate D600 for ENMAX.
  - The Commission determined that the existing DCG credit mechanism should be phased-out and discontinued.
- In AUC Decision 27047-D01-2022, the Commission found that:
  - The phase-out of DCG credits will substantially decrease billing determinant erosion, independent of implementation of the AMP, leaving the Commission unclear as to the further benefits to be derived from implementation of the AMP.
  - The ability of the AMP to reduce significant billing determinant erosion is no longer clear, given the phase-out of DCG credits.
- The Commission consequently questioned the value of implementing the AMP.
- As a result, the AESO considers it necessary to consider and address the relationship between billing determinant erosion, the AMP and DCG Credits.

The DCG Credit Mechanism

The following description of the DCG Credit mechanism was provided in AUC Decision 26090-D01-2021:

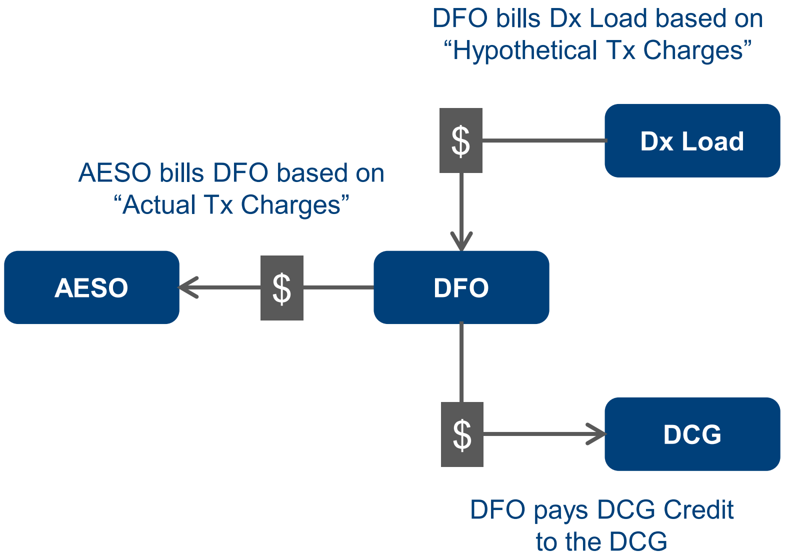
- DCG Credits are calculated based on the electrical energy delivered by the DCG to the distribution system and represent the difference between the AESO transmission charges (Rate DTS and Rate STS) the distribution utility must pay with the DCG in operation (Actual Tx Charges), and the hypothetical charges that would have been incurred if the DCG had not been in operation (Hypothetical Tx Charges).
- The amounts are calculated manually for each DCG using actual hourly metering data. The calculated credits are then allocated to, and recovered from, all load customers of that distribution utility.

Based on the above, the DCG Credit calculation can be simplified to:

$$\boxed{\text{DCG Credit} = \text{Hypothetical Tx Charges} - \text{Actual Tx Charges}}$$

where Actual Tx Charges are the Rate DTS and Rate STS charges received by the DFO.

Billing and Payment Flows for DCG Credits



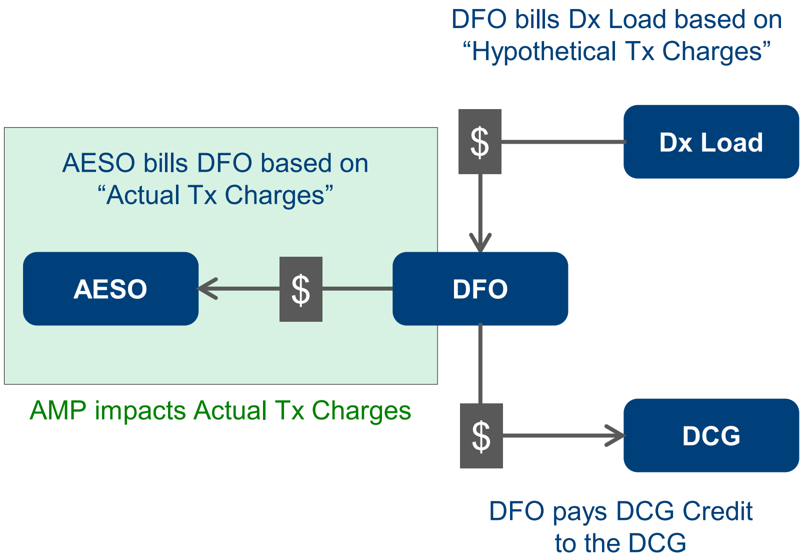
Impact of the AMP on DCG Credits

As described in the **Background & Ongoing Need** materials, the purpose of the AMP is to reflect the actual individual energy flows between the Tx and Dx systems, and to eliminate the artificial erosion of the DTS and STS billing determinants and the associated issues that causes. With the AMP in place, there will be an increase to the DTS and STS bills for DFO substations that have DCG (the Actual Tx Charges).

Hypothetical Tx Charges do not change under the AMP as the scenario used to determine these charges already assumed there is no DCG in operation (if a substation only has load flows, then the DTS bills would be the same under the current practice and the AMP, and there would be no STS bills).

Under the AMP, the calculated DCG Credits will therefore be reduced, because of the smaller difference between the unchanged Hypothetical Tx Charges and the increased Actual Tx Charges.

Changes to Billing and Payment Flows for DCG Credits After the AMP is Implemented



DCG Credit ↓ = Hypothetical Tx Charges – Actual Tx Charges ↑

Phase-Out of DCG Credits

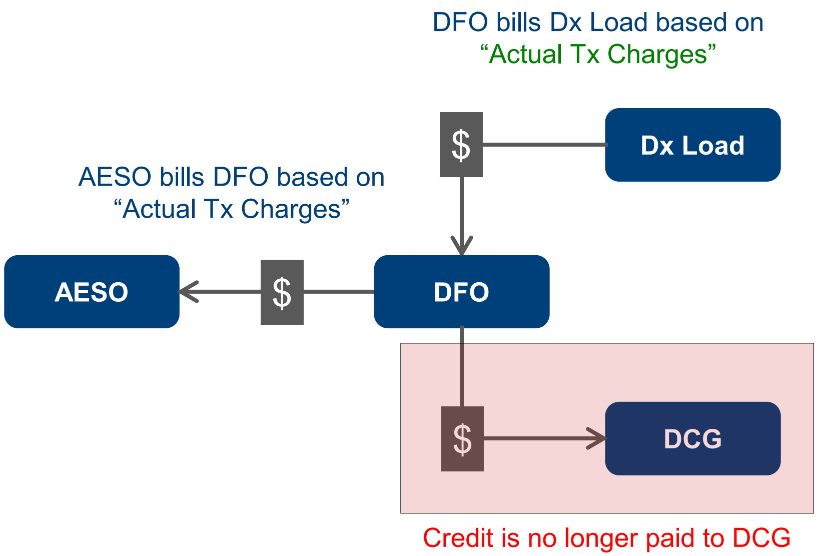
In AUC Decision 26090-D01-2021, the Commission approved the phase-out of DCG Credits as follows:

- The Commission decided on a four-year transition period, set on a declining basis, to phase out the Rate DTS portion of the DCG Credit mechanism.
- The Commission directed that ATCO Electric Ltd., ENMAX Power Corporation, and FortisAlberta Inc. calculate the Rate DTS portion of the DCG Credits the same way, but then apply the following multipliers to the calculated value before issuing the credit.

Year	First day when the multiplier will be applied	Multiplier
1	Jan 1, 2022	0.8
2	Jan 1, 2023	0.6
3	Jan 1, 2024	0.4
4	Jan 1, 2025	0.2
5	Jan 1, 2026	0

DCG Credit = (Hypothetical Tx Charges – Actual Tx Charges) x Multiplier

Changes to Billing and Payment Flows After DCG Credit Phase-Out

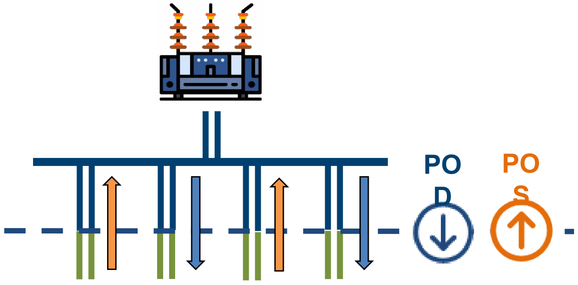


Phase-Out of DCG Credit Does Not Reduce Billing Determinant Erosion

The phase-out of DCG Credits does not resolve artificial billing determinant erosion, because billing determinants are a function of the physical energy flows to and from the Tx system. The billing determinant erosion is caused by the netting of these energy flows, and under the current measurement practice, only the elimination of reversing flows into the substation would address existing and future erosion; the phase-out of DCG Credits has no impact on the netting of energy flows.

Fewer DCGs may decide to connect without the DCG Credits in place, but this will impact neither the existing energy flows at the substation, nor the billing determinant erosion caused by the current netting practice. The rate of additional erosion may decrease, but it will still increase with new DCG, and as shown in the **Background & Ongoing Need** materials there is still a significant number of DCG applying to connect.

As part of Proceeding 26090, the AESO and other parties (including The Utilities Consumer Advocate and the DCG Consortium) agreed that though there is a relationship between the AMP and DCG Credits, the implementation of the AMP should continue to be considered separate and apart from any potential legacy treatment or transition period for DCG Credits because the decision to pursue the AMP was made for separate and distinct reasons, and the question of whether to implement the AMP is similarly distinct. This continues to be the case. The phase-out of DCG Credits does not "correct" the underlying billing determinant erosion issue intended to be resolved by the AMP.



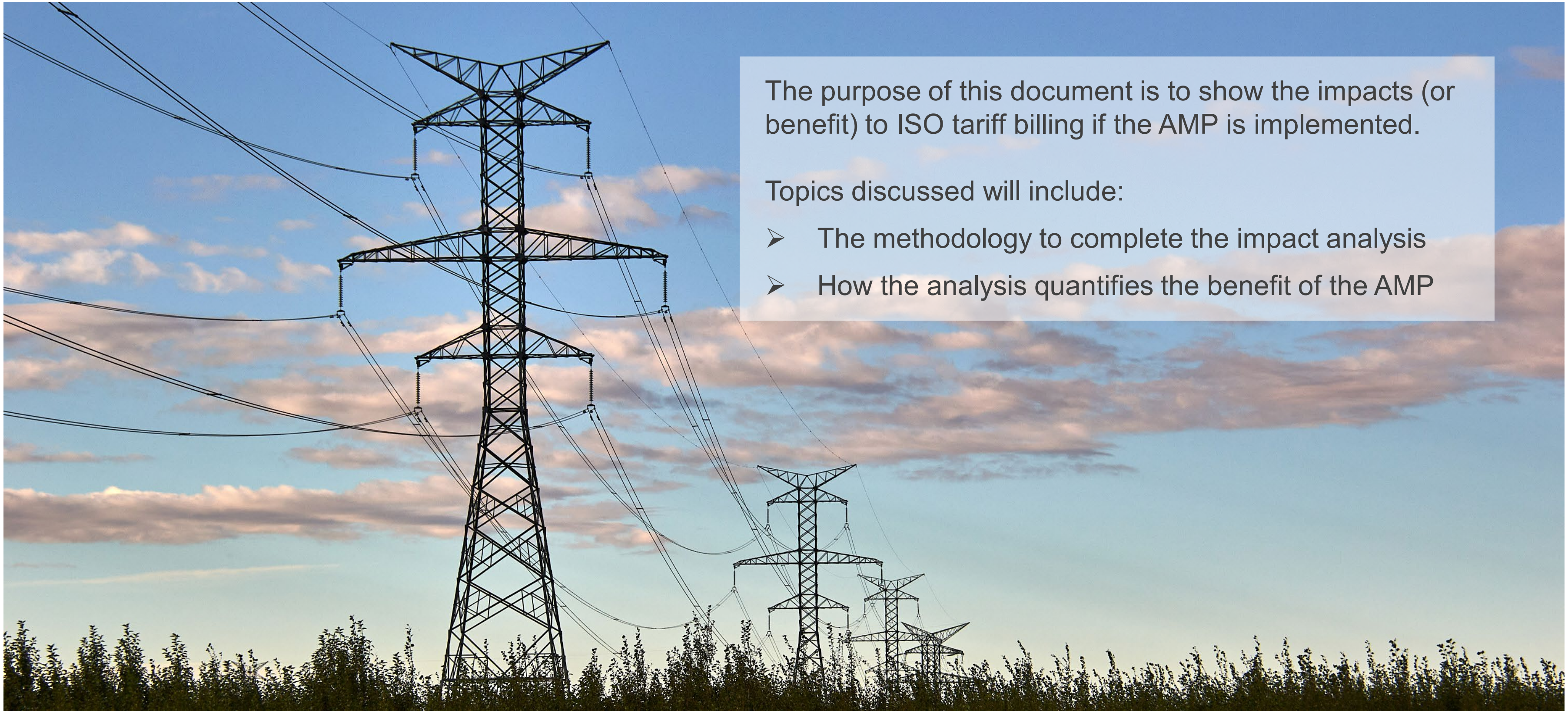
Under the current net measurement practice, inflows from the Dx system would continue to offset outflows to the Dx system, artificially eroding the billing determinants. This is true whether DCG Credits are in place or not.

Have questions? Please add them to the "Question Board" on the AMP AESO Engage page

AMP Engagement

Impact Analysis

Introduction



The purpose of this document is to show the impacts (or benefit) to ISO tariff billing if the AMP is implemented.

Topics discussed will include:

- The methodology to complete the impact analysis
- How the analysis quantifies the benefit of the AMP

The AMP Benefits ISO Tariff Billing

- As discussed in the **Background & Ongoing Need** materials:
  - As a result of increasing volumes of DCG, there has been an increasing number of reversing PODs, indicating that reversing flows from the distribution system into the substation are no longer low in volume or uncommon, and will only continue to grow.
  - Under the current measurement practice, the artificial erosion of billing determinants and impact to ISO tariff billing will continue to increase as well.
- As shown in the **Impact of BD Erosion on Billing Example**, the erosion of billing determinants will lead to higher rates for all MPs, and the ongoing misallocation of transmission costs between MPs. However, billing determinant erosion does not impact how much the AESO collects towards its revenue requirement each year (i.e., the AESO would not be "under-collecting" as a result of billing determined erosion). Billing determinant erosion creates a continued annual impact on who pays and how much they pay.
- Implementing the AMP will resolve the artificial billing determinant erosion that is occurring due to a measurement practice that nets flows entering and leaving a substation. Therefore, the benefit of the AMP is that it allows for billing and billing determinants that more accurately reflect each market participant's usage of the transmission system.

Methodology to Estimate Impact of the AMP on Billing

To quantify the benefit of the AMP, the AESO performed an impact analysis to compare ISO tariff billing for a historical year with and without the AMP in place. This indicative analysis provides an estimate of how billing determinants, rates, and market participant bills would change with the AMP in place.

The AESO's impact analysis can be broken down into the following steps:

Approximate Measurement Data

Develop a measurement dataset that approximates the separate flows entering and leaving the substation (for each substation connected to an electric Dx system)

→

Simulate Billing Determinants

Input the measurement data into the ISO tariff settlement system to simulate the billing determinants under the AMP

→

Calculate Rates and Bills

Calculate the updated rates and market participant bills using the updated billing determinants

Limitations and Assumptions

- As discussed in the **Background & Ongoing Need** materials, for each substation connected to a distribution system, the measurement data that the AESO receives from the MDMs is netted, meaning that the AESO cannot determine exactly what volume of load is served on each feeder. The AESO has interval-metered DCG data, which is information about how much energy a DCG produces for a specific interval. However, the AESO does not have visibility of where (more specifically, which feeder) the DCG production flowed.
- Additionally, the AESO does not have any feeder-specific information about the amount of load on each feeder at a substation. Without this information, the AESO would have to make assumptions regarding how much load is served at the feeder level. In order to develop these assumptions, the AESO spoke with DFOs to understand the typical interactions between load and DCG. From these conversations, it was evident that these interactions are substation- and feeder-specific, so without the feeder-level data, it is not possible to reasonably generalize how much load DCGs offset on the same feeder.
- Therefore, due to the above-described data limitations, for the AESO's impact analysis:
  - The AESO assumed a conservative scenario where DCG and loads are on separate, dedicated feeders (i.e., DCG did not serve any load on the same feeder). In reality, there will be substations where DCG is located on the same feeder as load, so the results from this analysis will show the ceiling for the number of substations that would require changes made to implement the AMP and, consequently, the ceiling for the estimated impact of the AMP.
  - The indicative analysis is only meant to provide an estimate of how billing is impacted by the AMP. It does not guarantee that implementing the AMP will result in the same changes as shown every year.

Approximate Measurement Data

Approximate Measurement Data

Develop a measurement dataset that approximates the separate flows entering and leaving the substation (for each substation connected to an electric Dx system)

To develop a measurement dataset that approximates the separate flows entering and leaving a substation, the AESO started with the actual measurement data for POD, and POS (aka EDG) that was used for ISO tariff billing in 2021.* The actual measurement data was received from MDMs for the billing that occurred for 2021.

Since the feeder-level data was not available, the AESO had to rely on the information it had available to approximate what flowed into the transmission system. The AESO has interval-metered DCG data (which includes large micro-generation), so from this the amount of DCG energy consumed by distribution load at the substation ("Consumed Energy") was calculated as:

Consumed Energy = 2021 Interval-metered DCG Data – 2021 Actual POS Data

Then, for the conservative scenario where DCG and load are on dedicated feeders, the following is a proxy for the feeder-level POD data the AESO would have received for the substation under the AMP ("2021 AMP Measurement Data"):

2021 AMP Measurement Data = 2021 Actual POD Data + Consumed Energy

Of the ~450 substations connected to a distribution system, 130 had non-zero DCG flows in 2021.

*See **Background & Ongoing Need** materials for discussion of measurement data types.

Simulate Billing Determinants

Simulate Billing Determinants

Input the measurement data into the ISO tariff settlement system to simulate the billing determinants under the AMP

The AESO input the 2021 AMP Measurement Data into its settlement system to simulate the DTS billing under the AMP. DTS charges recover most of the ISO tariff costs, so the impact of the AMP is most significant on DTS revenue recovery. This impact analysis focuses on DTS billing determinants and billing.

To learn more about billing determinants and how the ISO tariff is billed, please see the ISO Tariff Billing course on the AESO's Continuing Education Website.

The AESO settlement system produced the monthly billing determinants for each MP as though the AMP had been in place for 2021 ("2021 AMP BDs"). The billing determinants that this impact analysis focuses on are:

- Coincident Metered Demand;
- Billing Capacity; and
- Metered Energy.

Calculate Rates and Bills

Calculate Rates and Bills

Calculate the updated rates and market participant bills using the updated billing determinants

After acquiring the 2021 AMP BDs, the AESO compared the DTS rates and MP bills with and without the AMP in place. To calculate the monthly MP bills:

$$\text{MP Monthly Bill} = \text{MP Billing Determinants}_{\text{Month}} \times \text{Rate}$$

where the Rate is a function of the revenue requirement to be recovered through that particular billing determinant, and the total billing determinants (i.e., across all MPs) that it will be recovered through.

For a given year, the ISO tariff rates are set before the year begins, based on an estimated revenue requirement and forecasted billing determinants. In order to isolate for the impact of just the AMP on billing, the AESO calculated updated rates for the bulk and regional components* assuming that in both the with AMP and without AMP cases:

- There were no changes to the 2021 revenue requirement after it was forecasted.
- There is no forecast error for the billing determinants used to set rates. So, in the "with AMP" case, the forecasted billing determinants would equal the 2021 AMP billing determinants. And in the "without AMP" case, the forecasted billing determinants would equal the actual 2021 billing determinants.

*Only the rates for bulk and regional components were updated because the bulk, regional, and POD components recover the majority of the revenue requirement. POD rates were not updated because those rates are based on the investment cost function.

Impact to 2021 Measurement Data and Billing Determinants

To develop the 2021 AMP Measurement Data, Consumed Energy was added back to 130 substations.

Tariff Charge	*Billing Determinant*	*Impacted by the AMP?*	*2021 Actual Billing Determinants*	*Change Due to the AMP*	*% Change Due to the AMP*
DTS - Bulk System	Coincident Metered Demand	Yes*	93,115 MW	+ 2,700 MW	+ 2.9%
	Metered Energy	Yes	59,014 GWh	+ 1,400 GWh	+ 2.4%
DTS - Regional System	Billing Capacity	Some subs	154,679 MW	+ 249 MW	+ 0.2%
	Metered Energy	Yes	59,014 GWh	+ 1,400 GWh	+ 2.4%
DTS - Point of Delivery	Substation Fraction ("SSF")	-	-	-	-
	SSF x [Tiered] MW of Billing Capacity	Some subs	154,679 MW	+ 249 MW	+ 0.2%

*The coincident system peak for the months of September, November, and December also changed (15 minutes, 30 minutes, and 1 day, respectively).

As expected, under the AMP there is a higher quantity of DTS billing determinants (i.e., there is a reduction in billing determinant erosion). Additionally, if the coincident system peak interval changes for a month, then there could also be a change to the market participants that would be charged for their Coincident Metered Demand that month.

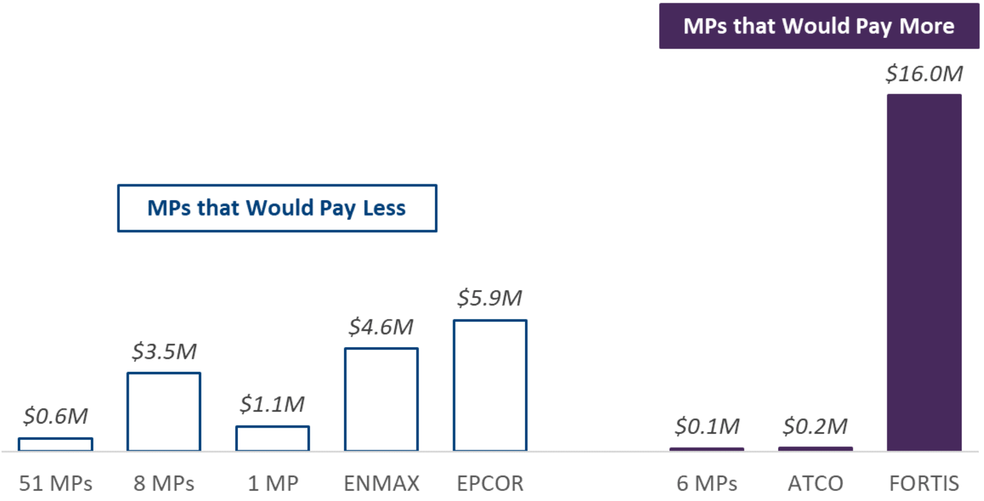
Impact to 2021 Rates

DTS Charge	Charge Component	Based on 2021 Actual Billing Determinants	Based on 2021 AMP Billing Determinants	Change Due to the AMP	% Change Due to the AMP
DTS - Bulk System	Coincident Metered Demand*	$10,906 /MW	$10,601 / MW	- $306 /MW	- 2.8%
	Metered Energy	$1.21 /MWh	$1.18 /MWh	- $0.03 /MWh	- 2.5%
DTS - Regional System	Billing Capacity	$2,997 /MW	$2,992 /MW	- $4.83 /MW	- 0.2%
	Metered Energy	$0.92 / MWh	$0.89 /MWh	- $0.02 /MWh	- 2.2%

*The coincident system peak for the months of September, November, and December also changed (15 minutes, 30 minutes, and 1 day, respectively).

As expected, under the AMP the DTS rates for all transmission market participants would be lower.

Impact to Market Participant Bills



The difference in the sum of bills for MPs that would have paid less to the sum of bills for MPs that would have paid more (~$0.5M) is due to the over-collection of POD and Ancillary Services components in the "with AMP" case since these rates were not updated and billing determinants increased.

*The indicative analysis is not meant to provide an exact estimate of how much more or less a particular market participant would pay after the AMP is implemented, since their actual bills would be a function of the actual rates that are in place and their actual billing determinants at that time.

As expected, the indicative analysis* shows that under the AMP, the annual amounts that each MP would pay for DTS would change.

MPs would have paid less because the AMP led to lower rates for all. MPs with higher billing determinants (generally, higher consumption) would see a larger reduction in their bills.

DFOs that had large amounts of DCG flows would have paid more. Some non-DFO MPs also paid more due to the coincident system peak interval changing.

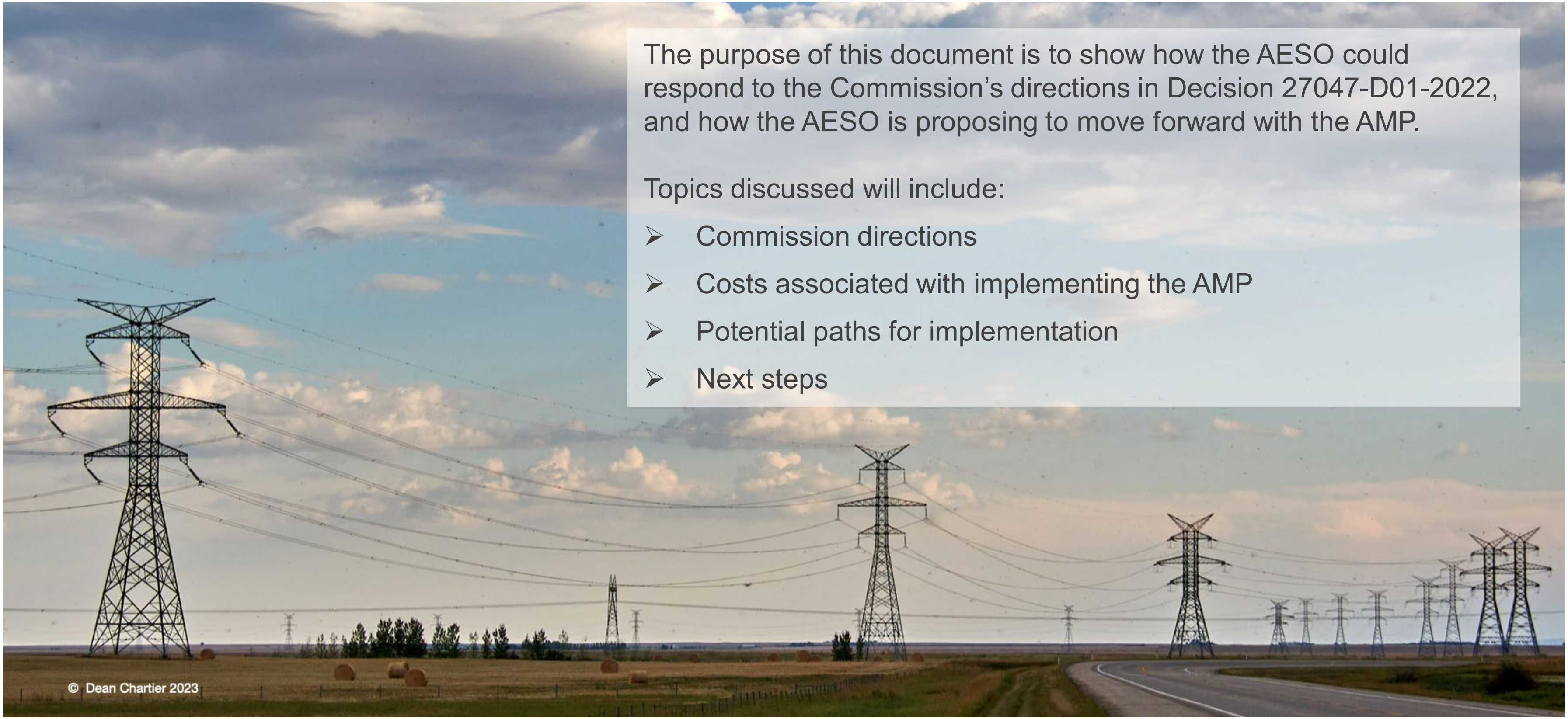
As discussed in the **Background & Ongoing Need** materials, this misallocation will continue to occur annually until the AMP is in place. The amount of misallocation will also continue to grow as more DCG connect.

Have questions? Please add them to the “Question Board” on the AMP AESO Engage page

AMP Engagement

Moving Forward With the AMP

Introduction



The purpose of this document is to show how the AESO could respond to the Commission's directions in Decision 27047-D01-2022, and how the AESO is proposing to move forward with the AMP.

Topics discussed will include:

- Commission directions
- Costs associated with implementing the AMP
- Potential paths for implementation
- Next steps

Commission Directions From Decision 27047-D01-2022

- In AUC Decision 27047-D01-2022, the Commission did not approve the AMP implementation plan that the AESO proposed. The Commission also found that the AESO is not required to file a further application to implement the AMP.
- However, the Commission stated that if the AESO wishes to file a further application to implement the AMP, then the AESO is directed to include the following information in any future AMP implementation plan application:
  - AACE Class 3 (-20% to +30%) estimates and forecast completion date for all scopes of work proposed in the implementation plan. Alternatively, the AESO could include in its implementation plan mechanisms for cost review and oversight of future phases of AMP implementation.
  - AACE Class 5 (-50% to 100%) estimates for the total theoretical maximum cost of implementation across all phases.
  - Quantification of the benefits of implementation of the AMP, including a cost-benefit analysis.
- These requirements are addressed in the slides that follow.

Capital Costs for Implementing the AMP

- As discussed in the **Background & Ongoing Need** materials, the changes required to implement the AMP at a substation may be physical or administrative in nature. The Commission's directions from AUC Decision 27047-D01-2022 regarding “AACE Class Estimates” relate to physical changes, further discussed below.
- At substations where changes to implement the AMP would be purely administrative in nature, work that is part of day-to-day operations will be done to update MPDRs, meter data systems, and SAS agreements. In these cases, there are no capital costs required to implement the AMP because the substation already has feeder-level meters.
- At substations where changes would be physical in nature, implementing the AMP would require a transmission facility project for the installation by the applicable TFO of feeder-level metering, which would involve capital spending. Cost estimates for transmission facility projects are required to be completed in accordance with Section 504.5 of the ISO rules, *Service Proposals and Cost Estimating*. As indicated in the AESO Information Document #2015-002R associated with this rule, the AESO has adopted the Association for the Advancement of Cost Engineering (AACE) cost management practices as a foundation for estimating the costs of transmission facility projects. Table 1 in Information Document #2015-002R sets out the typical purpose and methodology used for each of the estimate classes.

AACE Class 3 Cost Estimate Considerations

- Information Document #2015-002R states that AACE Class 3 estimates are typically used for budget authorization or control (e.g., Service Proposal Estimates) when approximately 10-40 per cent of the project deliverables are complete.
- Since the implementation of the AMP has not been approved and the necessary assessments have not been completed to confirm which substations would require physical changes, it would be premature to initiate these transmission facility projects and advance them sufficiently (i.e., complete project deliverables) in order to develop AACE Class 3 estimates and forecast a completion date for the project.
- The AESO has also discussed the cost, timing, and amount of work required to develop AACE Class 3 estimates with TFOs for the substations that would most likely require physical changes. They advised the AESO that, for each substation, they would require:
  - Approximately 2-6 months of time to prepare an AACE Class 3 estimate; and
  - Up to $75k to complete the work required to develop the AACE Class 3 estimates. This work would include site visits, site assessments, feasibility assessments, project planning, preliminary engineering, and the development of execution plans among other tasks.
- Ultimately, the AESO has not proceeded with obtaining AACE Class 3 estimates because it did not seem prudent to incur the costs or to direct TFOs to do the work if implementation of the AMP is not approved.

Cost Review and Oversight Mechanism

- Since the AESO has determined that it is not prudent to proceed with obtaining AACE Class 3 estimates without approval to implement the AMP, the AESO has considered alternative cost review and oversight mechanisms that could be relied upon.
- If physical changes are required at a substation to implement the AMP, then the AESO would direct the applicable TFO to initiate a transmission facility project. The AESO is proposing that the cost review and oversight for these transmission facility projects triggered by the AMP follow the same process as any other transmission facility project, as follows:
  - TFOs would include these projects in a TFO General Tariff Applications to provide the Commission with oversight of the projects that are expected to occur, including a preliminary cost estimate (likely AACE Class 5 level of accuracy).
  - Since the replacement and installation of metering equipment would constitute an alteration to a transmission facility, TFOs would file the applicable facilities application with the Commission to request approval of the alteration (e.g., a Facility Application or, if the alteration is sufficiently minor, a Letter of Enquiry). This application would require an AACE Class 3 cost estimate for the Commission's economic assessment, pursuant to AUC Rule 007.
  - For all transmission facility projects (regardless of whether the project is part of a connection project or system project), as the project is executed, the TFO will provide AACE cost estimates of increasing accuracy to the AESO in accordance with Section 504.5 of the ISO rules, *Service Proposals and Cost Estimating*.

Theoretical Maximum Cost of Implementing the AMP

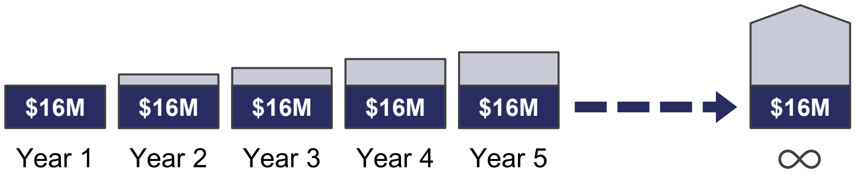
- In order to estimate the total theoretical maximum cost of implementing the AMP, two inputs are required: (1) the number of existing substations that may require the installation of feeder-level meters, now and in the future and (2) the AACE Class 5 estimated capital cost per substation.
- In connection with the AESO's previously proposed AMP implementation plan, TFOs advised the AESO that the AACE Class 5 estimate for a transmission facility project to replace existing transformer-level metering with feeder-level metering is $750,000 per substation. This estimate may deviate significantly for any specific substation, but substation-specific estimates can only be provided once a TFO has been directed to initiate the project.
- Based on the AESO's preliminary analysis, of the approximately 450 existing substations that are connected to a distribution system, there are approximately 70 that do not have feeder-level metering. A number of these 70 substations would require physical changes due to existing reversals at the point in time when the AMP is initially implemented. In addition, there will be substations that would require physical changes at some point in the future if new reversals were to materialize. The AESO does not expect that all 70 substations will actually require feeder-level metering in the future (because not all will have reversals); however, for the purposes of determining a theoretical maximum cost, the full number (70) will be used as an input.
- Therefore, the theoretical maximum cost of implementing the AMP at all existing substations that are connected to a distribution system is:

$750,000 x 70 substations = $52.5M (-50% / +100%)

- A portion of those costs would be incurred when the AMP is initially implemented, but it is anticipated that the rest of the costs would be spread out over an indefinite number of years as the evolving interaction of load flows and new DCG at a substation will dictate when the physical changes to implement the AMP would be required at a specific substation.

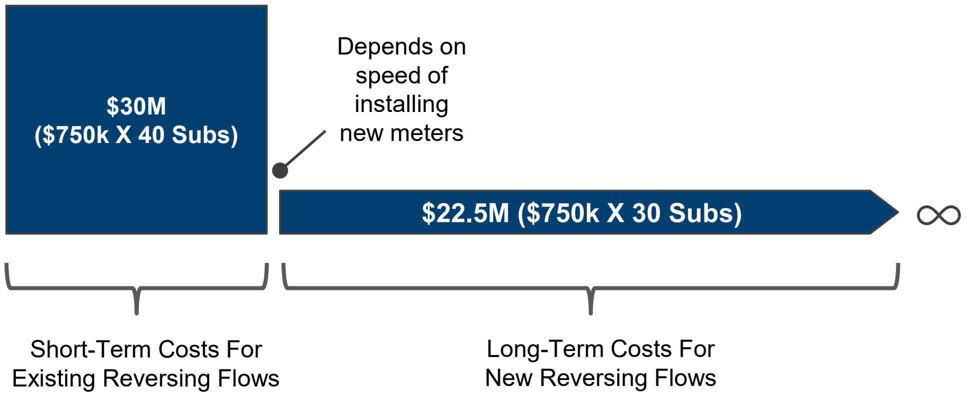
The Total Costs and Benefits of Implementing the AMP

Misallocations Without Implementing the AMP*



Under the AESO's currently approved rate design, the misallocation of ISO tariff billing across all MPs would occur annually and continue indefinitely if the AMP is not implemented. The amount of the misallocation will depend on the specific rates and billing determinant volumes for a year but will generally increase every year as inflows from the Dx system to the Tx system increase with new DCG.

Capital Costs to Implement the AMP*



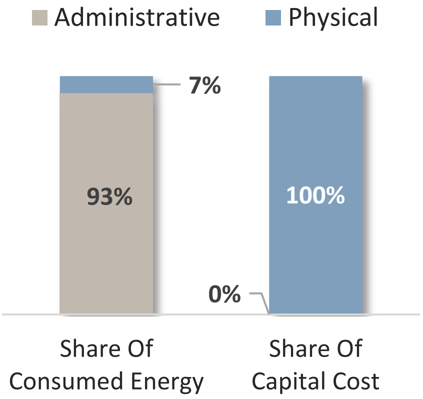
Implementing the AMP would require installing feeder metering at any substation with transformer metering that currently has reversing flows (40 of the 130 substations in the impact analysis). This cost would be incurred in the short-term, based on the pace of meter installation projects.

Remaining substations with transformer metering (30 of the ~70 existing substations that do not have feeder-level metering) would not incur costs until reversing flows materialize over an indefinite number of years. Some substations may never have reversing flows, never incurring these costs.

*Based on the 2021 amounts from the **Impact Analysis** material.

Breakdown of Costs & Erosion by Type of Change

The following table and chart compare the change in consumed energy, billing determinant impact and implementation costs for substations that would require administrative and physical changes (based on the 2021 **Impact Analysis** material).



Type of Change Required at Substation	# of Subs	Capital Costs Required for Implementation ($750,000/substation)	DTS Billing Determinant	Increase in 2021 BDs Post-AMP
Administrative	90	None	CMD (MW) Billing Capacity (MW) Metered Energy (GWh)	+ 2,516 MW + 233 MW + 1,312 GWh
Physical	40	$30.0M	CMD (MW) Billing Capacity (MW) Metered Energy (GWh)	+ 207 MW + 16 MW + 101 GWh

- The majority of substations (90 of the 130 in the impact analysis) would require only administrative changes to implement the AMP and incur no capital costs.
- The majority of Consumed Energy (and associated billing determinant increases) was at the substations that only require administrative changes. The impact to bills for these MPs was that they would pay approximately $16M more.
- The 2021 impact analysis is based on a conservative scenario that shows the ceiling for the estimated impact of the AMP for both billing determinants and costs.

Moving Forward With AMP Implementation

- Billing determinant erosion has been steadily increasing and will continue to increase as more DCG connects. Additionally, there is a significant number of existing substations with reverse flows. For these reasons, the AESO recommends implementing the AMP as soon as possible.
- In accordance with Decision 27047-D01-2022, the AESO can move forward with the implementation of the AMP in one of two ways:
  - By not implementing the AMP, as the Commission found that the AESO is not required to file a further application proposing an implementation plan for the AMP; or
  - If the AESO wishes to do so, it could file an AMP implementation plan to implement the AMP without legacy treatment, in alignment with the Commission's direction to provide additional cost information.
- Between these two extremes, the AMP could also be implemented with legacy treatment, meaning that the AMP would not be required to be implemented at some (or all) existing substations that are connected to a distribution system.

Moving Forward With AMP Implementation (cont.)

- Legacy treatment can be approached in many different ways to prioritize different objectives and yield different outcomes. For example, legacy treatment can be provided:
  - Based on a point in time, if the primary objective of the legacy treatment is to reduce the impact of the AMP on DCG Credits.
  - Based on a maximum budget for costs or on minimizing ratepayer costs, if the primary objective is to minimize costs.
  - Based on whether changes required to implement the AMP are technically feasible, if the primary objective is ease of implementation.
- Based the AESO's impact and cost-benefit analysis, the majority of the billing determinant erosion currently occurs at substations that would only require administrative changes (i.e., no capital costs required) to implement the AMP.
  - As a result, one possible approach to implementing the AMP would be to provide legacy treatment to existing substations that already have reverse flows and would require physical changes to implement the AMP. If new reversing flows were to materialize at some point in the future, substations would not be provided legacy treatment (similarly, substations could lose legacy treatment if the amount of reverse flows increases). Immediate changes to implement the AMP would therefore be limited to substations that only require administrative changes, which would yield a significant amount of benefit, at no capital cost in the near-term.

Next Steps

- Because the AESO does not currently have approval to implement the AMP with legacy treatment, and because it is unclear from AUC Decision 27047-D01-2022 whether the Commission would agree that the AMP should be implemented at all, the AESO is first proposing to file an application to confirm the Commission's approval of the AMP and, if that confirmation is provided, whether the AMP should be implemented with or without legacy treatment.
- The AESO currently intends to file this application in April of 2023, subject to completion of its engagement with stakeholders.
- If the AESO's April 2023 application is approved, the AESO would then file any required AMP implementation plan and/or compliance filing, in alignment with the Commission's confirmation of the AMP and direction regarding legacy treatment.

Have questions? Please add them to the "Question Board" on the AMP AESO Engage page

Totalized Billing

Within a Substation

History of Totalized Billing Provisions

Tariff Effective	Subsection Heading	Tariff Section
Jan 1, 2021 – Present	Totalized Billing at Separate Substations	Section 10, Settlement and Payment Terms
Jul 1, 2011 – Dec 31, 2020	Totalized Billing	Section 13, Financial Security, Settlement and Payment Terms

Since 2011, the ISO tariff has had a version of totalized billing provisions as part of its terms and conditions regarding settlement.

Rate DTS requires that the AESO apply Rate DTS separately at *each* point of delivery. Similarly, Rate STS requires that the AESO apply Rate STS separately at *each* point of supply. The totalized billing provisions allow the AESO the ability to “totalize” (i.e., combine) more than one point of delivery (or more than one point of supply) into a single Rate DTS (or Rate STS) bill.

Totalized billing is only permitted in the circumstances described in the totalized billing provisions and is also limited to the totalization of billing under the same service. That is, a point of delivery can only be totalized with other points of delivery (and similarly for points of supply).

The current totalization provisions approved in Decision 22942-D02-2019 specify that totalized billing is applicable to points of delivery (or points of supply) at *separate substations*. Prior to Decision 22942-D02-2019, the totalized billing provisions were silent on whether the points of delivery (or points of supply) being totalized could exist within the same or at separate substations.

Issues with Current Totalized Billing Provisions

- As noted in the AESO's amended application in Proceeding 22942, the changes to the Financial Security, Settlement and Payment Terms section of the ISO tariff, which include the totalized billing provisions, were meant to be administrative in nature. However, the distinction of "separate substations" created a lack of clarity regarding if and how totalization within the same substation is permitted.
- A substation may itself be referred to as "a POD" (or "a POS"), implying that a substation has only a single point of delivery (or point of supply). However, a substation may also, for many reasons, have multiple points of delivery (or points of supply) within it.
- Since multiple PODs (or POSs) can exist within the same substation, the ability to totalize those multiple PODs (or POSs) under the same demand transmission service (or supply transmission service) should apply.
  - Without the ability to totalize at the same substation, the AESO would be required to separately contract and bill for DTS (or STS) at each of the points of delivery (or points of supply) within the substation, which is administratively inefficient.
  - Additionally, not allowing the totalization of multiple points of supply in a substation would create an artificial barrier that limits the ability of a market participant to aggregate some or all of its generating units as contemplated by subsection 5 of Section 501.10 of the ISO rules, *Transmission Loss Factors*.

Proposed Revision: Totalized Billing Within a Substation

Totalized Billing Within a Substation

10.4 *For the purposes of billing and contracting for **system access service**, the **ISO** may totalize multiple **points of delivery** under Rate DTS, or multiple **points of supply** under Rate STS, located at a single substation, for the same **market participant**, unless the **market participant** requests otherwise.*

- The AESO first proposed amendments to the current totalized billing provisions as a part of its previous AMP implementation application because the revisions would have assisted in an administratively efficient implementation of the AMP.
- However, the totalized billing provision that the AESO is proposing to section 10 of the ISO tariff should broadly apply to all market participants.
- Alongside the upcoming AMP application, the AESO will submit an application for the proposed revision to the ISO tariff to include the Totalized Billing within a Substation provision.
  - The outcome of the upcoming AMP application will not impact the AESO's proposed revisions for the totalized billing provision. However, the AESO notes that approval of the totalized billing provisions will allow for a more efficient implementation of the AMP (as it relates to contracting and billing).
  - Approval of the proposed totalized billing provision does not result in the implementation of the AMP.

Have questions? Please add them to the “Question Board” on the AMP AESO Engage page

Illustrative Example: Impact of Billing Determinant Erosion on ISO Tariff Billing

This simplified example illustrates the impact of billing determinant erosion on DTS rates and revenue collection.

To learn more about billing determinants and how the ISO tariff is billed, please see the ISO Tariff Billing course on the AESO's Continuing Education website.

This simplified example assumes that:

- The AESO's annual revenue requirement to recover transmission costs from loads in Alberta is $100 and remains unchanged year over year;
- Actual load for a year will match the AESO's forecast (i.e., there is no forecast error);
- The full revenue requirement is recovered through a single variable DTS rate ($/unit);
- There is no revenue collected in-year from Rider C adjustments or the deferral account reconciliation ("DAR") mechanism. True-ups occur after the year is over;
- The AESO determines the annual DTS rate before the start of each calendar year;
- There are only two MPs that use the transmission system (MP1 and MP2); and
- The loads for MP1 and MP2 are identical (same load shapes and levels) and remain unchanged over time.

Based on the assumptions above, the rates and billing determinants determined for upcoming Years 1 and 2 are as follows:[1]

Table 1: AESO Forecast Billing Determinants and DTS Rate (Years 1-2)

	Year 1	Year 2
Revenue Requirement ($)	100	100
Forecasted Billing Determinants MP1	5	5
Forecasted Billing Determinants MP2	5	5
DTS Rate ($/unit)	$10/unit	$10/unit

As shown in Table 1 for Year 1, the AESO forecasts 10 units of load split between MP1 and MP2 (5 units each). This is a 50/50 split of system use so the AESO's revenue requirement is collected equally from both parties.

[1] The AESO notes that the numbers in the figures and tables for the simplified example may not add exactly due to rounding.

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i. *A reduction in billing determinants will impact the AESO's rates and revenue collection*

At the start of Year 2, MP2 adds a generator, which produces 1 unit per year. Assuming everything else stays the same, the addition of the generator: (i) reduces the actual billing determinants for MP2 by 1 unit; and (ii) drives down Rate DTS revenue collection for the system by 1 unit.

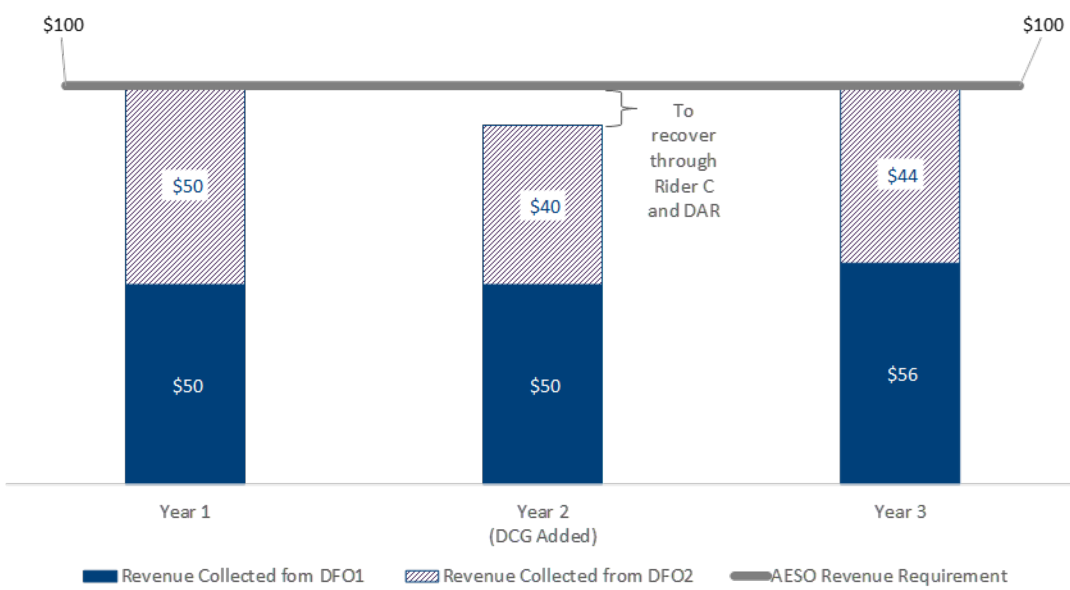
As shown in Table 2 below, Year 2 rates were set at the end of Year 1, so the Year 2 rates will be based on forecasted billing determinants that don't include the generator flows. The AESO's forecasted billing determinants for the Year 3 Rate DTS calculation will reflect the lower transmission usage for MP2 from Year 2. Consequently, the lower forecasted billing determinants directly increase the DTS rate for Year 3, which applies to all Rate DTS customers.

Table 2: AESO Forecast Billing Determinants and DTS Rate (Year 3)

	Year 1	Year 2	Year 3
Revenue Requirement ($)	100	100	100
Forecasted Billing Determinants MP1	5	5	5
Forecasted Billing Determinants MP2	5	5	4
DTS Rate ($/unit)	$10/unit	$10/unit	$11/unit

As shown in Figure 1 below, MP2 will pay lower Rate DTS revenue to the AESO in Year 2. and onwards, due to the decreased flows. The allocation of costs between MP1 and MP2 shifts from $50/$50 in Year 1 to $56/$40 in Year 3 because MP2 billing determinants are lower relative to MP1s.

Figure 1: Comparison of Annual Revenue Collected by the AESO



ii. The AESO must collect the entire revenue requirement

In this simplified example, since the MPs billing determinants dropped in Year 2 after the Year 2 rates were set, there is a shortfall in the annual revenue collected by the AESO in Year 2.[2]

In reality, as the AESO's revenue requirement for a year must be recovered entirely, the AESO will use two "true-up mechanisms" to balance the revenue that the AESO collects for a year with the SAS costs for that year:

1) Rider C for in-year adjustments to collect additional revenue during the year if the AESO is trending towards under-collection, or to refund revenue if the AESO is trending towards over-collection.

2) The DAR to true-up revenue and costs after the year is complete.

These true-up mechanisms are applied across all market participants based on their proportion of billing determinants. So in the simplified example, the Year 2 shortfall will be recovered proportionally from both MP1 and MP2.

iii. Conclusions

From the illustrative example, we can conclude that:

1) If a market participants billing determinants decrease, they'll pay less for DTS.

2) Lower billing determinants result in higher rates for all market participants.

3) The AESO must collect its entire revenue requirement, so any in-year shortfalls will subsequently be collected from all market participants.

4) Since the AESO must collect its entire revenue requirement, if one market participant pays less, then others will pay more to make up the difference.

If the billing determinants for MP2 were artificially low (or under-represented) due to how billing determinants were measured for ISO tariff billing, then the costs that **both** MP1 and MP2 paid would not be reflective of their use of the transmission system. Additionally, rates for all market participants would increase for subsequent years based on the lower billing determinants overall.

[2] This is because this simplified example does not include any in-year Rider C or DAR amounts.

Reversing PODs

Energy Flowing From The Distribution System Onto The Transmission System

Discussion Paper

Final

April 30th, 2007

Table of Contents

1.0 INTRODUCTION

1.1. Intent

The intent of this paper is for the AESO and EUB to seek stakeholder input and come to a decision on how to properly account for energy that flows onto the transmission system from the distribution system. This paper provides the information describing the background, a number of potential options, and the process for stakeholders to submit input, comments and other alternatives for consideration.

1.2. Executive Summary

Load Settlement Agents are responsible for calculating the total energy consumed in a load settlement zone, and allocating that energy across the load customers. The energy consumed in a load settlement zone is generally understood to be the sum of all energy flowing into the zone, less any energy flowing out of it.

In some instances where there is a large amount of generation connected to the distribution system, the supply from these generators is sufficient enough to supply the entire distribution load in the area. Any excess generation then flows out of the distribution system and back on to the transmission system. This flow of energy is generally referred to as a Reversing POD, and this energy is not accounted for in the load settlement zone calculation.

The AESO has estimated that approximately $1.75M dollars per year of energy is not being accounted for in the load settlement zone calculations. This energy remains in Unaccounted For Energy (UFE), and is allocated across distribution load customers. As the number of distribution generators increase, and in light of the forthcoming micro-generation initiative, this situation will increase in magnitude.

In view of this issue, the AESO proposes to establish a standard for calculating and reporting Reversing POD energy, and for properly accounting for this energy in the load settlement calculations. These standards will ensure that load settlement zone totals are being correctly calculated, and that energy is being properly allocated within those zones.

2.0 BACKGROUND INFORMATION

2.1 Measurement Points

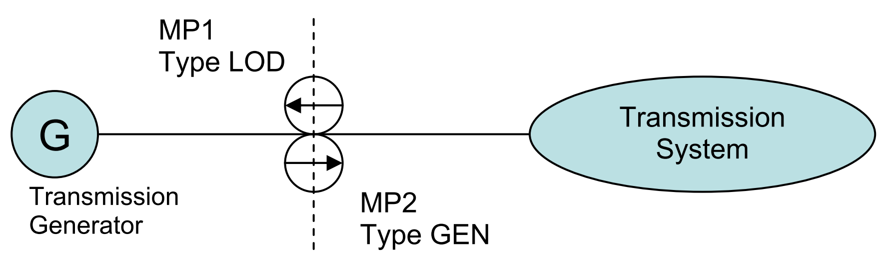
A Measurement Point (MP) is assigned for each interconnection point in the province between the transmission and distribution systems, between the Alberta Interconnected Electric System and other systems, between load settlement zones, and between generators and the transmission or distribution systems. Each one of these points has a calculation to determine what the 15 minute net energy flow is at this point, and each MP is assigned a data type.

Data types are generally described as follows:

LOD: Power flowing from the transmission system to the distribution system or to a customer connected to the transmission system
GEN: Power flowing from a generator onto the transmission or distribution system, or from out of province onto the distribution system
IMP: Power flowing into the AIES from another province, or power flowing into one load settlement zone from another zone
EXP: Power flowing out of the AIES to another province, or power flowing out of one load settlement zone to another zone

Currently MWh reported under these points are not allowed to be negative. In the case where energy flows physically in both directions, such as a transmission generator, there are two MPs assigned, one for each direction of energy flow. A calculation is performed on a 15 minute basis to determine the net direction of energy flow, and reported under the appropriate MP. Negative energy on the related MP is zeroed out.

The above situation is illustrated below.



If Load = 6 and Gen = 4
MP1 = 6 – 4 = 2 Type LOD
MP2 = 4 – 6 = -2 = 0 Type GEN

If Load = 4 and Gen = 6
MP1 = 4 – 6 = -2 = 0 Type LOD
MP2 = 6 – 4 = 2 Type GEN

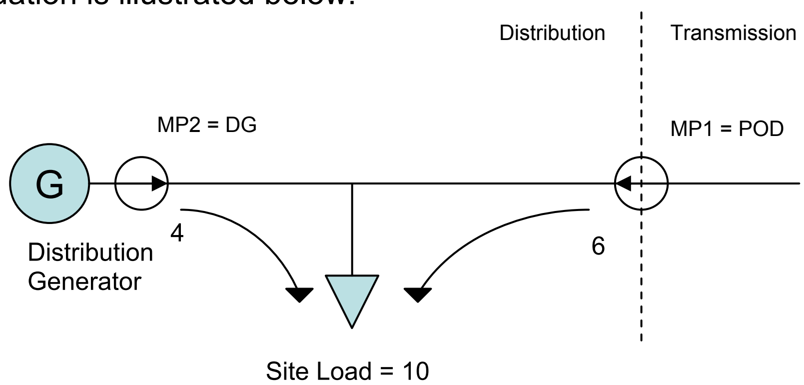
2.2 Reversing PODs

The flow of energy from the transmission system to the distribution system is assigned an MP as described above, commonly referred to as a Point of Delivery, or POD. As energy flows at these points are typically only in one direction (from the transmission system to the distribution system), there are no

MPs assigned to account for any energy that flows from the distribution system to the transmission system. This has been considered an acceptable situation.

There are also numerous generators located on the distribution system. These generators are typically small in size, and are measured by an MP assigned a GEN type. Generators on the distribution system combine with the energy flowing through the POD to supply the distribution loads.

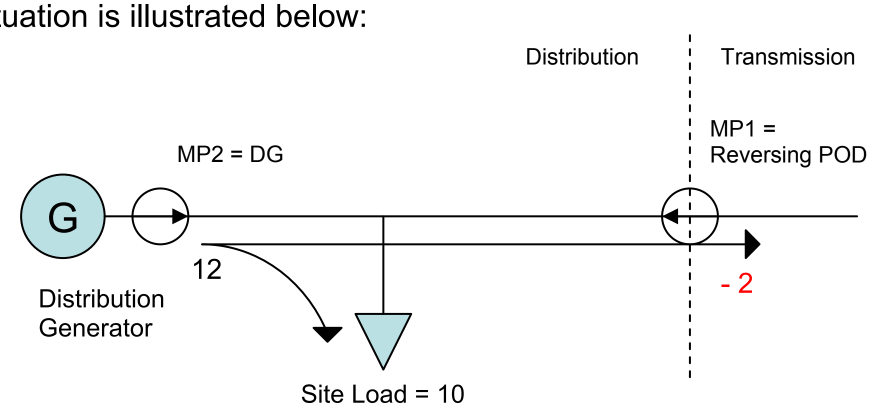
This situation is illustrated below:



MP1 = 6 Type LOD
MP2 = 4 Type GEN

When either the number or size of generators installed grows large enough, it becomes possible to supply the entire load on the distribution system, and the remaining generation flows onto the transmission system. This situation is referred to as a Reversing POD. The existing MP of type LOD is calculated as a negative number, and according to existing practices it is then zeroed out. As there is no MP assigned to account for energy flowing from the distribution system to the transmission system, this energy goes unaccounted for.

This situation is illustrated below:

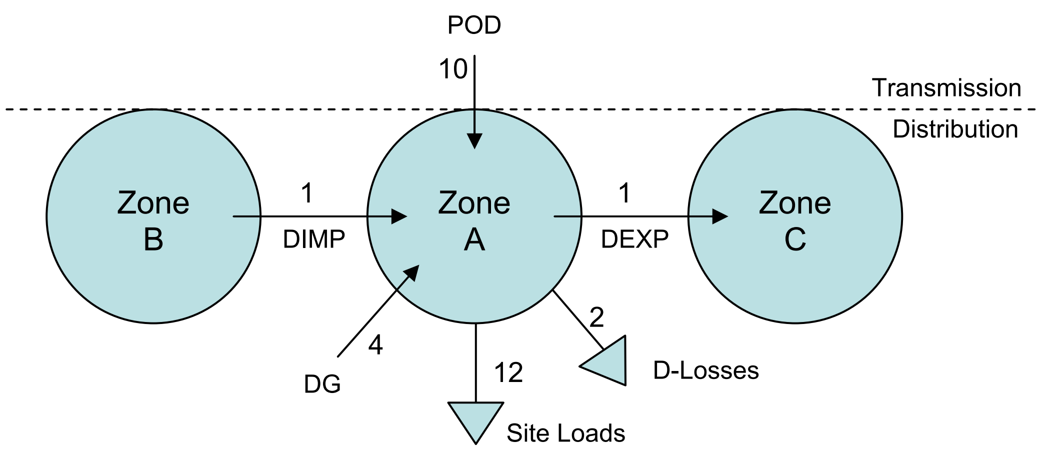


MP1 = -2 = 0 Type LOD
MP2 = 12 Type GEN

2.3 Zone Calculations

Load settlement agents calculate their total zone load based on the inputs and outputs to and from their zone. A zone will typically include energy flowing from the transmission system into the zone (POD), energy flowing into the zone from distribution generators and border supply points (DG), energy flowing into the zone from another zone (DIMP) and energy flowing out of the zone to another zone (DEXP). The difference between the zone load and the site loads in a zone is the Unaccounted For Energy (UFE) and the distribution line losses incurred to supply the site loads. Ideally the zone load less any distribution line losses equals the site loads, and UFE ends up being zero.

This calculation is illustrated below:

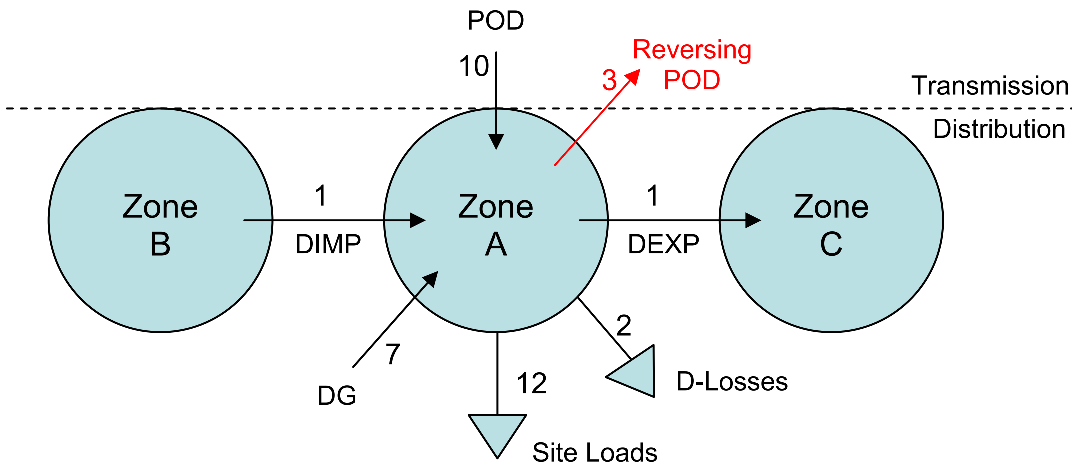


Zone A = POD + DG + DIMP – DEXP
Zone A = 10 + 4 + 1 – 1 = 14

UFE = Zone A - Site Loads – Losses
UFE = 14 – 12 – 2 = 0

When reversing PODs are introduced to the zone due to an increase in distribution generation, there is now energy flowing out of the zone that is not accounted for. As this energy is not subtracted from the total zone load, the calculated load for the zone is now artificially high. Since the site loads and losses to supply those sites haven't changed, this extra energy is now accounted for in the UFE.

This calculation is illustrated below.



Zone A = POD + DG + DIMP – DEXP
Zone A = 10 + 7 + 1 – 1 = 17

UFE = Zone A – Site Loads – Losses
UFE = 17 – 12 – 2 = 3

By not accounting for the flow of energy out of the settlement zone through the reversing PODs, UFE is now artificially higher than it would normally be. This UFE is then allocated across the load customers, despite the fact that it has physically left the distribution system.

2.4 Impact to Load Settlement

It is estimated that in 2005 approximately 25000 MWh of Reversing POD energy was not accounted for by load settlement. This is estimated to be $1.75M annually in energy charges that are being allocated to distribution load customers for energy that has flowed onto the transmission system. As the number of distribution generators installed on the distribution system continues to increase, it is likely that the amount of energy flowing through the Reversing PODs will increase as well.

3.0 OPTIONS FOR ACCOUNTING FOR REVERSING PODS

In order to properly account for the energy that is flowing out of load settlement zones and onto the transmission system, a standard method of reporting this data needs to be developed, and the load settlement engines need to be able to correctly perform their calculations using this data.

3.1 Option 1: Alter the Load Settlement Calculation

Option 1 proposes that Reversing PODs continue to be reported as type GEN, and that the Load Settlement calculation engines be altered as required to ensure that the appropriate MPs be added or subtracted as necessary to obtain the correct zone totals. This would mean that each individual MP would need to have an add or subtract characteristic, rather than that characteristic being common to the data type.

Example:

MP1:	Standard POD	Type LOD
MP2:	Standard DG	Type GEN
MP3:	Reversing POD	Type GEN

MP1 added to zone
MP2 added to zone
MP3 subtracted from zone

Pros:

- No change to data reporting for the MDM
- No change to data storage systems
- No change to current standards for calculating GEN/LOD
- Most flexible for any future changes that are required

Cons:

- No differentiation between Reversing PODs and DGs
- Potentially significant changes to Load Settlement calculation engines to base addition or subtraction on individual MPs rather than data types
- Extra maintenance required to maintain individual MP calculations

3.2 Option 2: Add a New Data Type

Option 2 proposes that a new data type be created that would be used for Reversing PODs. This would allow for Load Settlement calculation engines to assign add or subtract characteristics based on the data type rather than the individual MPs.

Example:

MP1:	Standard POD	Type LOD
MP2:	Standard DG	Type GEN
MP3:	Reversing POD	Type REV (as an example)

Type LOD added to zone
Type GEN added to zone
Type REV subtracted from zone

Pros:

- Does not require Load Settlement calculation engines to individually assign MPs an add or subtract characteristic
- No change to existing data
- Differentiates between Reversing PODs and DGs

Cons:

- Changes to all existing systems to produce and accept a new data type
- Differentiates between transmission generation that is produced from a transmission connected generator or produced from the distribution system

3.3 Option 3: Alter the Existing Data Types

Option 3 proposes that the existing data types be altered to differentiate between being Distribution connected and Transmission connected. This would allow for Load Settlement calculation engines to assign add or subtract characteristics base on the type rather than the individual points.

Example:

MP1:	Standard POD	Type TLOD
MP2:	Standard DG	Type DGEN
MP3:	Reversing POD	Type TGEN

Type TLOD added to zone
Type DGEN added to zone
Type TGEN subtracted from zone

Pros:

- Differentiates transmission and distribution connected points of all types
- Does not differentiate between transmission generation that is produced from a transmission connected generator or produced from the distribution system
- Does not require Load Settlement calculation engines to individually assign points an add or subtract characteristic

Cons:

- Requires a change to existing data types, and possible back-conversion of all existing data
- Changes to all existing systems to produce, accept, store and work with new data types
- This requires an increase in the size of field for data type (from 3 to 4)

3.4 Option 4: Allow for Negative Power Flow

Option 4 proposes that Reversing PODs be accounted for by using a negative sign in the existing LOD data. This would allow for Load Settlement calculation engines to assign add or subtract characteristics base on the type rather than the individual MP. Currently any negative energy flow on a POD is accounted for by zeroing out the LOD data and reporting that power as GEN data.

Example:

MP1:	Standard POD	Type LOD
MP2:	Standard DG	Type GEN
MP3:	Reversing POD	Type LOD with Negative Values

Type LOD added to zone
Type GEN added to zone

Pros:

- Does not require Load Settlement calculation engines to individually assign points an add or subtract characteristic
- Does not require any new data types to be created

Cons:

- Requires a change in existing systems to allow for negative numbers
- Breaks from existing standards for data flows
- Uses different methodology for calculating and reporting data flows from all other types of points

3.5 Option 5: Do Nothing

Option 5 proposes that the existing situation be allowed to persist.

Example:

MP1:	Standard POD	Type LOD
MP2:	Standard DG	Type GEN
MP3:	Reversing POD	Not reported or accounted for

Type LOD added to zone
Type GEN added to zone

Pros:

- No changes to existing systems

Cons:

- Energy that has left the distribution system is included in UFE and is paid for by all distribution customers

3.6 Summary of Option Impacts

Option	Type	MDM Impact	LSA Impact	AESO Impact	Conclusion
1	GEN	None	System change to calculate zone based on individual MPs (This is a significant change from calculating based on data types)	None	Viable, depending on the scope of changes to the LSA calculation engines (Expected to be large, but to a limited number of systems)
2	REV	System change to produce new data type (This data type fits within the parameters of existing data types)	System change to accept new data type (This data type fits within the parameters of existing data types)	System change to accept new data type (This data type fits within the parameters of existing data types)	Viable, depending on the scope of changes for a new data type (Expected to be small, but required for all systems)
3	TGEN	System change to produce new data types Conversion of existing data to new data types (This data type requires a change to the data parameters)	System change to accept new data types Conversion of existing data to new data types (This data type requires a change to the data parameters)	System change to accept new data types Conversion of existing data to new data types (This data type requires a change to the data parameters)	Not preferred, due to the required mass conversion of existing data, and the required change in data parameters
4	LOD	System change to allow for calculation of negative numbers	System change to accept negative numbers	System change to accept negative numbers.	Not preferred, due to the deviance from the existing methodology of reporting energy flows, and potential system changes.
5		None	None	None	Unacceptable, due to the improper allocation of energy

4.0 PROCESS SCHEDULE

This discussion paper and the feedback received as a result of it will provide the basis for developing a standard on Reversing PODs. The process activities and associated dates are summarized as follows:

Completion Date	Process Activity
2007-05-02	EUB/AEOS issue this discussion paper to market participants
2007-05-16	EUB hosts stakeholder meeting to discuss this paper
2007-06-04	Written comments from stakeholder due
2007-06-18	EUB/AESO issues decision and implementation plan
2007-06-25	EUB issues letter of intent for proposed SSC rule changes
2008-02-01	SSC rule changes take effect

5.0 STAKEHOLDER FEEDBACK

The AESO/EUB is seeking stakeholder input, in writing, on the following items:

1. Any additional information on the treatment of reversing PODs that is not covered in this document, including background information, future developments, etc. and other options you wish to put forward for consideration.

2. Impacts to your existing process/systems for each of the stated options.

3. Costs and/or savings, including qualitative and quantitative measures, for the stated options.

4. The option you support and why, as well as options you cannot support and why not.

5. Suggested implementation timelines.

Please direct any comments about this discussion paper in writing to Chris Connoly at Chris.Connoly@aeso.ca (cc Rob Thomas at Robert.Thomas@eub.ca) by 2007-06-04.

AMP Engagement | Acronyms & Terms

For a list of acronyms and short-form terms used throughout the AMP Engagement materials, please see the following:

Term	Definition
AACE	Association for the Advancement of Cost Engineering
AESO	Alberta Electric System Operator
AMP	Adjusted Metering (or Measurement) Practice
AUC	Alberta Utilities Commission
CMD	Coincident Metered Demand
DCG	Distribution Connected Generation
DFO	Distribution Facility Owner (owner of an electric distribution system)
DTS	Demand Transmission Service
Dx	Distribution (system or facilities)
EDG	Excess Distributed Generation
EUB	Energy and Utilities Board
GUOC	Generating Unit Owner's Contribution
ISO	Independent System Operator
MDM	Meter Data Manager
MP	Market Participant
MPDR	Measurement Point Definition Record
POC	Point Of Connection
POD	Point Of Delivery
POS	Point Of Supply
SAS	System Access Service
SSF	Substation Fraction
STS	Supply Transmission Service
TFO	Transmission Facility Owner
Tx	Transmission (system or facilities)
UFE	Unaccounted for Energy

Alberta Electric System Operator

www.aeso.ca

Calgary Place, 2500, 330-5th Avenue SW Calgary, AB T2P 0L4

Phone: 403-539-2450 | Fax: 403-539-2949

THE FUTURE OF ELECTRICITY

Adjusted Metering Practice Q&A Session

March 23, 2023

Notice

In accordance with its mandate to operate in the public interest, the AESO will be audio recording this session and making a high-level summary of the meeting available to the general public at www.aeso.ca. The accessibility of these discussions is important to ensure the openness and transparency of this AESO process, and to facilitate the participation of stakeholders. Participation in this session is completely voluntary and subject to the terms of this notice.

The collection of personal information by the AESO for this session will be used for the purpose of capturing stakeholder input for the Adjusted Metering Practice stakeholder sessions. This information is collected in accordance with Section 33(c) of the Freedom of Information and Protection of Privacy Act. If you have any questions or concerns regarding how your information will be handled, please contact the Privacy Officer, Legal and Regulatory Affairs at 2500, 330 – 5th Avenue S.W., Calgary, Alberta, T2P 0L4, by telephone at 403-539-2890 or by email at privacy@aeso.ca.

Land Acknowledgement

LAND ACKNOWLEDGEMENT

AESO is committed to actively taking part in reconciliation and believes in the National Truth and Reconciliation Centre recommendation of honouring the First Peoples of these lands.

Indigenous Peoples have inherent kinship ties with the land, which we should all respect and help restore. We encourage everyone to think of their relationship with the land, when their ancestors first stepped onto Turtle Island, and recognize that First Peoples have been here since time immemorial.

We would like to acknowledge that we are on the Traditional Territory of Treaty 7, which settlers have renamed to Calgary, Alberta. These lands hold the hearts and footsteps of many First Nations, Métis and Inuit, and we would like to especially recognize the Tsuut'ina First Nation, the Blackfoot Confederacy, which is made up of the Kainai, Piikani, and Siksika Nations, the Stoney Nakoda tribes, and is also the homeland of the Métis Nation of Alberta, Region 3.

We are grateful to have the opportunity to work and be present in this territory together with many Indigenous Peoples from across Turtle Island. We offer this acknowledgement as a stepping stone towards reconciliation by honouring the First Peoples of the land that today we call home, and as an expression of our commitment to Indigenous communities.

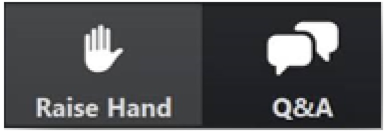
AESO Stakeholder Engagement Framework

Stakeholder Participation

- The participation of everyone here is critical to the engagement process. To ensure everyone has the opportunity to participate, we ask you to:
  - Listen to understand others' perspectives
  - Disagree respectfully
  - Balance airtime fairly
  - Keep an open mind

Using Zoom: Asking questions

- All attendees join the webinar in listen-only mode (cameras are disabled and microphones muted)
- Before asking your question, please introduce yourself including your organization
- Two options to ask questions via **computer or smartphone**:
  1. Click the “Q&A button” at any time
     - Type your questions into the Q&A window at any time
     - You’re able to up-vote questions that have already been asked
  2. During the session
     - Click the icon to raise your hand (click again to lower) and the host will see that you have raised your hand
     - The host will unmute your microphone and you, in turn, will need to unmute your microphone before you can ask your question
     - Your name will appear on the screen, but your camera will remain turned off
- To ask questions via **conference call**
  – To raise your hand, press *9 on your phone’s dial pad; the host will be notified
  – To toggle between mute and unmute, press *6 on your phone’s dial pad
  – Your number will appear on the screen



Purpose and Introduction

- The purpose of this session is to provide an opportunity to stakeholders to discuss any further questions or concerns that they may have and to explore any areas where clarification is still required on the AMP
- The session will be an open question and answer (Q&A) format; stakeholders will be able to ask questions, and the AESO panel will answer to the best of their abilities
  – Any questions that are unable to be answered during the session will be posted in a FAQ document following the session
- No additional material will be presented at the session

Registrants (as of March 22, 2023)

- Alberta Direct Connect Consumer Association (ADC)
- Alberta Utilities Commission (AUC)
- AltaLink Management Ltd.
- ATCO & ATCO Electric Ltd.
- Campus Energy
- Capital Power
- City of Red Deer
- EPCOR
- Evolugen
- Industrial Power Consumers Association of Alberta (IPCAA)
- Lionstooth Energy
- Member of the Public
- Power Advisory
- TransAlta Corporation
- Utilities Consumer Advocate (UCA)
- Versorium Energy Ltd.

Schedule and Next Steps

- **March 6, 2023** | Materials posted and "Share Your Questions" board opened on AESO Engage
- **March 23, 2023** | Virtual Q&A session
- **March 30, 2023** | The "Share Your Questions" board on AESO Engage will stay open for another week; please add any remaining questions you may have
- **April 6, 2023** | The AESO will post a FAQ document with responses to questions or concerns that stakeholders raise. The FAQ will contain all questions or concerns from both the "Share Your Questions" board and those posed during the Q&A session
- **April 21, 2023** | Take the opportunity to submit your comments on the continued need and benefits of the AMP and potential approaches to implementing AMP (extension to allow stakeholders to review FAQ before submitting comments)
- **April-May 2023** | The AESO will review and consider stakeholder feedback for incorporation into the application, with a target of filing in May

AMP Materials

- AMP materials posted on March 6, 2023
  - Section 1 | Background & Ongoing Need
  - Section 2 | DCG Credits and the AMP
  - Section 3 | Impact Analysis
  - Section 4 | Moving Forward with the AMP
  - Section 5 | Totalized Billing

Session Close-Out

- We want to thank you for attending the AMP Q&A Session and we would appreciate your feedback on the session
- Launch poll
  - The purpose of the session was clear
  - I found this session valuable

Thank you

Project Report

06 March 2023 - 31 March 2023

AESO Engage

Adjusted Metering Practice

BANG THE TABLE engagementHQ

Stakeholder Questions

IDEAS

Clarification Areas | Share Your Questions

Visitors 34	Contributors 7	CONTRIBUTIONS 94

20 March 23

AltaLink - Lee Ann Kerr

VOTES 0

a. Does the AESO intend to do further analysis that includes DFO substations that do not reverse flow onto the transmission system?

A reverse flow on one feeder at a POD will not necessarily result in result flows onto the transmission grid and can still result in incorrect billing for the POD, as can flows that happen behind feeders.

20 March 23

AltaLink - Lee Ann Kerr

VOTES 0

a. Can the AESO provide materials on the process (stakeholder input, EUB/AESO decision, etc.) ?

Reference: The Reversing PODs Discussion Paper

20 March 23

AltaLink - Lee Ann Kerr

VOTES 0

Is it necessary to make physical changes to subs to implement AMP? Is a settlement fix an option?

Reference: The Reversing PODs Discussion Paper

20 March 23

Lionstooth-ErikaGoddard

VOTES 2

Substation Breakdown

Produce a slide with a clear breakdown of substations, including what the following number of substations quoted in the materials refer to; 450 subs, 130 subs, 70 subs, 53 subs, plus any others missed. Also include a breakdown of substations by MP (similar to as shown in Section 3, Slide 11) with the number of subs per MP that would be impacted by the implementation of AMP.

20 March 23

Lionstooth-ErikaGoddard

VOTES 1

POS Impacts

Per Section 1, Slide 8, there are POS impacts too. Complete an analysis of the impact of the AMP on Rate STS.

IDEAS

Clarification Areas | Share Your Questions

20 March 23

Lionstooth-ErikaGoddard

VOTES 1

Data

Provide the data behind the figure in Section 1, Slide 14.

20 March 23

Lionstooth-ErikaGoddard

VOTES 1

Dx Load Growth

Reconcile the statement made in Section 1, Slide 15 “there is currently enough DCG ca pacity in the project list to almost double installed capacity, with little new distribution lo ad to consume it” with statements made in the AESO’s “Net-Zero Emissions Pathways Report,” specifically Figure 6 (pdf page 27) that shows electrical vehicle load growth, ce rtainty the vast majority of which will be served from the Dx system, adding over 6,000 GWh of energy by 2035.

20 March 23

Lionstooth-ErikaGoddard

VOTES 2

Further Detail on Section 3

This engagement would benefit from a more detailed explanation of Section 3 (this ma y need to be its own session).

20 March 23

Lionstooth-ErikaGoddard

VOTES 2

Savings per Customer

What do the savings calculated translate into in $/MWh for end-use DFO customers (S ection 3, Slides 9-10)?

20 March 23

Lionstooth-ErikaGoddard

VOTES 2

Cost Analysis

The AUC’s AMP Decision was issued May 31st, 2022, around 9 months ago. The AES O’s 2023 budget for “Own Costs” is $133 million, including $5.6 million for “Contract Se rvices and Consultants” (2023 BDP Stakeholder Presentation, Oct-2022). Given the TF Os quoted 2-6 months (leaving 3 months for further AESO analysis) and $75k (or 1.3 % of the AESO’s consultant budget) to develop a AACE Class 3 estimate, why did the AESO not even do this for one substation?

20 March 23

Lionstooth-ErikaGoddard

VOTES 1

Cost per Customer

What does the cost of implementing the AMP translate into in $/MWh for end-use DFO customers, assuming all $53 MM in costs are implemented (reference: Section 4, Slide 7)?

20 March 23

Lionstooth-ErikaGoddard

VOTES 1

Feasibility

When would implementing the AMP be not technically feasible (Section 4, Slide 11)?

IDEAS

Clarification Areas | Share Your Questions

20 March 23

AltaLink - Lee Ann Kerr

VOTES 1

Can the AESO do an impact analysis on each indivi dual DFO POC using current billing determinants an d adding back DCG interval metered data?

20 March 23

Lionstooth-ErikaGoddard

VOTES 1

Impact Analysis by Stakeholder

For each of the following groups, explain the impact of implementing the AMP, with a s pecific focus on cost / savings; load customers, existing DCG, future DCG, DFOs, TFO s, and the AESO.

20 March 23

Lionstooth-ErikaGoddard

VOTES 1

Timing

There are 11 working days between when comments are due, and the AESO's propos ed filing deadline. Is the AESO even considering changes to their AMP proposal based on stakeholder feedback?

20 March 23

AltaLink - Lee Ann Kerr

VOTES 0

Can the AESO confirm that there are currently 40 su bs that have reversing flows onto the transmission s ystem today that require feeder meter

Reference: Slid 8 of Section 4, Capital Costs to Implement the AMP

20 March 23

AltaLink - Lee Ann Kerr

VOTES 0

Can the AESO identify the # of subs that are not ne cessarily reversing flow onto transmission system b ut have reversing flows on feeders?

Reference: Slid 8 of Section 4, Capital Costs to Implement the AMP

20 March 23

AltaLink - Lee Ann Kerr

VOTES 4

a. Would the AESO agree that distribution connecte d load customers receive the same level of transmis sion service as T connected customers?

20 March 23

AltaLink - Lee Ann Kerr

VOTES 2

Would the AESO agree that the load billing determin ant for this feeder and/or POC would be reduced? Would this also be BD erosion?

Consider an existing DFO feeder is currently serving 15 MW's of load (i.e 15 MW, 70% LF) and at a future date a 10 MW DCG (i.e 10 MW, 80% capacity factor) is added dow nstream of the substation on this same DFO feeder.

IDEAS

Clarification Areas | Share Your Questions

20 March 23 KSC-Rosa Twyman VOTES 2	How many of the substations that have DCG connected to them currently have feeder metering and what was the purpose for installing it?
20 March 23 KSC-Rosa Twyman VOTES 1	Which feeders at a substation are part of the transmission system and which feeders are part of the distribution system?
20 March 23 KSC-Rosa Twyman VOTES 2	Does the existing feeder level metering currently measure the energy being delivered and supplied to the transmission system?
20 March 23 KSC-Rosa Twyman VOTES 0	Do the substations with existing feeder level metering net the delivered and supplied energy as the non-feeder metering substations do?
20 March 23 KSC-Rosa Twyman VOTES 0	Under AMP is the AESO installing meters to measure the energy being supplied to the transmission system?
20 March 23 KSC-Rosa Twyman VOTES 0	Is the AESO proposing to measure the energy being supplied to the distribution system using different feeders at the substation?
20 March 23 KSC-Rosa Twyman VOTES 2	Reconcile the AESO position that it does not plan for energy supplied by DCGs, with the anticipated increased energy supply from DCG.

IDEAS

Clarification Areas | Share Your Questions

20 March 23
KSC-Rosa Twyman
VOTES
2

Why does the AESO not plan for energy delivered to the transmission system from DCG?

20 March 23
KSC-Rosa Twyman
VOTES
0

Why does the AESO plan for energy delivered to the transmission system from BTF generation of the transmission connected generators?

20 March 23
KSC-Rosa Twyman
VOTES
1

Has the AESO considered the optimal integration of the energy provided by DCG in accordance with the AUC's Decision 26911-D01-2022?

20 March 23
KSC-Rosa Twyman
VOTES
0

How will the implementation of AMP reduce sunk co sts?

20 March 23
KSC-Rosa Twyman
VOTES
0

Does AMP compel payment for use of existing trans mission based on a larger amount of billing determin ants by changing the measuring point?

20 March 23
KSC-Rosa Twyman
VOTES
1

How is the use of the transmission system changing because of measuring the energy flows at different p oints (at transmission feeder)?

20 March 23
KSC-Rosa Twyman
VOTES
2

How is the proposed AMP different from the AMP pr oposal submitted in Proceeding 27047, which was ul timately rejected by the AUC?

IDEAS

Clarification Areas | Share Your Questions

20 March 23
KSC-Rosa Twyman
VOTES
0

Example on PDF12 of the Background, does it show the issue is the method of calculation of energy flow s and not the actual metering?

20 March 23
KSC-Rosa Twyman
VOTES
0

Which components of the transmission system the DFO is using to supply their own loads, as per PDF p 8 of the Background presentation?

20 March 23
KSC-Rosa Twyman
VOTES
1

How is the transmission system used when DFOs u se energy from DCG connected to the DFO's syste m to serve needs of DFO load customers?

20 March 23
KSC-Rosa Twyman
VOTES
0

Is under EUA 100% of TFOs' yearly revenue require ment required to be recovered in addition to a 100% recovery of the AESO's own costs?

20 March 23
KSC-Rosa Twyman
VOTES
3

What parts of the transmission (bulk, regional, POD) are used when a DCG energy is solely used by DF O load connected to the same DFO?

20 March 23
KSC-Rosa Twyman
VOTES
0

Must each TFO's revenue requirement be recovered entirely as part of the AESO's revenue requirement f or a year?

20 March 23
KSC-Rosa Twyman
VOTES
0

All things equal, if the AESO collects 100% of its rev enue requirement regardless, how will MPs pay less ?

IDEAS

Clarification Areas | Share Your Questions

20 March 23

KSC-Rosa Twyman

VOTES

0

If the AESO collects 100% of its revenue requireme nt, will some MPs pay more and some less as the s ame amount is to be collected?

20 March 23

KSC-Rosa Twyman

VOTES

0

Can AESO estimate AMP costs when the necessar y assessments have not been done to confirm whic h substations require physical changes?

20 March 23

KSC-Rosa Twyman

VOTES

1

Are immediate changes to implement the AMP limited to substations that only need administrative c hanges fair to DFOs with different cost?

20 March 23

VEL-Codd

VOTES

0

Does implementing AMP incentivize more or less efficient use of the transmission system?

AMP is proposed to address flows within substations, particularly those on 25 kV buses . How many 25 kV buses and 25 kV switchgear have been upgraded as a result of intr a-substation flows identified by the AESO? For each upgrade, what proportion of the c osts were paid by the system and what proportion was paid by construction contributio n and investment?

20 March 23

VEL-Codd

VOTES

0

Has the AESO considered whether DFOs will pursu e bypass projects to mitigate the cost increases cau sed by AMP?

25 kV buses and switchgear could be located within either a transmission substation or an electric distribution system. The possibility of credible bypass projects would justify maintaining current substation totalization policy for the same reasons the AESO maint ains existing Duplication Avoidance Tariffs.

20 March 23

PowerAdvisory-Christine-Runge

VOTES

0

Feeder level load data

Why did the AESO not work with DFOs to obtain data of load served by each feeder in order to do a more accurate impact assessment?

IDEAS

Clarification Areas | Share Your Questions

20 March 23

PowerAdvisory-Christine-Runge

VOTES
0

$16m cost shifting

Is the $16m per year shown in slide 8 of the “Moving Forward With the AMP” slide dec k is the amount of money that would be shifted annually from one set of ratepayers to a nother, consistent with the information shown in slide 11 of the impact deck?

20 March 23

PowerAdvisory-Christine-Runge

VOTES
0

Applicability of AMP

Is the AMP proposed to apply at all substations in Alberta or only DFO substations?

20 March 23

PowerAdvisory-Christine-Runge

VOTES
0

Data by DFO service territories

Can the AESO break down the 70 substations which do not have feeder-level metering , and the 30 of those substations with reversing flows (referenced for instance on slide 8 of the “Moving Forward With the AMP” slide deck), between DFO service territories, t o enable a more accurate comparison between costs and benefits?

28 March 23

PowerAdvisory-Christine-Runge

VOTES
0

$52.5m Cost Estimate

I asked this at the session, but was asked to file a written question as well. The AESO noted at the session that the $750k (-50% / +100%) is a high-level estimate from TFOs for what would be the cost to install feeder level meters at an average substation and th at there may be some substations where the cost could be much higher or much lower. If the TFOs provided a class 5 estimate of a "typical" substation, does that mean the tot al estimate of $52.5m might not be accurate to -50% / +100%? If so, can the AESO pro vide a more accurate range around the $52.5m? i.e. if there may be a handful of subst ations with significantly higher costs, should we consider the $52.5m to be accurate to +150% or +200% instead of +100%? Thanks.

28 March 23

PowerAdvisory-Christine-Runge

VOTES
0

Retroactive Connection Charges

The AESO noted at the consultation session that it doesn’t want to discuss cost treatm ent at this time, but rather plans to leave that topic to an implementation compliance fili ng after AMP is approved by the Commission. Can the AESO confirm it does not inten d to apply any retroactive connection charges that may be applicable to DCGs already past their final investment decision? The AESO suggested at the session that it may be willing to add this principle to its AMP application. Please confirm this willingness. Tha nks.

29 March 23

IPCAA

VOTES
0

Implement the administrative solution and wait.

Implement the administrative solution and wait on the metering decision until the "futur e" Tariff becomes clearer.

IDEAS

Clarification Areas | Share Your Questions

29 March 23

AltaLink - Lee Ann Kerr

VOTES

0

Does the AESO consider SSF=1 only for DFOs to b e a deviation of the principle of postage stamp rates ?

Proceeding 25848 saw the Commission approve a substation fraction equal to one ON LY FOR DFOs

29 March 23

AltaLink - Lee Ann Kerr

VOTES

4

a. Would the AESO agree that distribution connected load customers receive the same level of transmission service as T connected customers?

COMMENTS

1

9 March 23

Lionstooth - Geoff-Lester

Or, stated another way: As shown in the figure on Section 1, Slide 8 a series of distribution feeders with a dispatchable DCG (including natural gas fired generation and storage) ONLY make use of the 25kV transformer bus during periods when the DCG is operating. So in a situation where the DCG was running continuously, these feeders, and their associated load customers, would ONLY be using a small portion of the substation, and NONE of the radial and or bulk/regional system.

Adjusted Metering Practice

Q&A Session and Question Board Summary and AESO Replies

Date: April 6, 2023

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Table of Contents

Purpose

The AESO is providing this Q&A Session and Question Board – Summary and AESO Replies ("AESO Summary & Replies") as discussed at the March 23, 2023 Q&A Session as part of the AESO's ongoing stakeholder engagement for the Adjusted Metering Practice (AMP). The responses below, organized by theme/topic area, endeavor to provide additional information to assist stakeholders in preparing feedback to be submitted by April 23, 2023.

The AESO received substantial questions and requests for clarification from stakeholders both through the open Q&A session, as well as through the AESO Engage "Share your Questions" section. The AESO appreciates all the questions and comments posted to the Share Your Questions section of the AESO Engage page for the AMP and the discussion at the March 23, 2023 Q&A session. A summary of the questions asked on AESO Engage and at the March 23, 2023 session is provided below, together with the AESO's responses to the questions, organized by theme. The questions that stakeholders have asked will inform the AESO in the preparation of its upcoming application to the Alberta Utilities Commission (AUC) regarding the AMP.

Metering and Measurement Background

Stakeholders have raised questions about the Reversing PODs Discussion Paper referred to in the AESO's AMP engagement materials, and about the history of meters at substations connected to electric distribution systems.

No.	Question from AESO Engage "Share Your Questions"	Organization
1	Can the AESO provide materials on the process (stakeholder input, EUB/AESO decision, etc.)? Reference: the Reversing PODs Discussion Paper	AltaLink Management Ltd.
2	How many of the substations that have DCG connected to them currently have feeder metering and what was the purpose for installing it?	Kalina Distributed Power, Signalta Resources, Campus Energy Partners LP

AESO Response

The Reversing PODs Discussion Paper, along with the associated Electric Utilities Board (EUB) Decision, informed the content and development of AUC Rule 021: Settlement System Code Rules. The AESO has not been able to obtain and does not have a formal decision record from the EUB reflecting its approval, in 2007, of a new measurement type to address "excess" DCG; however, the new data type resulting from the EUB's decision can be found in the current AUC Rule 021.

The AESO's previous *Measurement System Standard* was in effect from September 18, 2007 to March 17, 2021. The *Measurement System Standard* stated that the following criteria would be used in the development of AESO functional specifications as well as TFO proposals to provide service:

> Revenue Metering is applied to two types of distribution circuits which can be classified as Urban and Rural. Urban circuits have lumped metering, i.e. the revenue metering is located on the

secondary of the transformer which in turn feeds one or more feeders. Rural feeders cover a large geographic area and consequently require individual circuit metering, i.e. revenue meters are applied to each circuit.

Anecdotally, rural substations generally have feeders that are longer and cover much larger geographical areas than rural substations, and there was a benefit identified in having individual visibility of the feeders for the purpose of disturbance and power quality analysis. The requirement for feeder meters at rural substations was therefore built into the *Measurement System Standard* to ensure that these meters would be in place. Due to the nature of the feeders in urban centers (and the much larger number of feeders in each substation), this requirement was not added for the urban substations, although the *Measurement System Standard* did allow for the transmission facility owner (TFO) to request feeder metering if they identified the need.

Meters and Measurement

Stakeholders have raised questions about meters at a substation and how the data from revenue meters is turned into the measurement data (i.e. billing determinants) used for billing. At the March 23, 2023 Q&A session, stakeholders specifically asked why meters on every feeder are required because there are already feeders at the distribution level.

No.	Question from AESO Engage "Share Your Questions"	Organization
3	Which feeders at a substation are part of the transmission system and which feeders are part of the distribution system?	Kalina Distributed Power, Signalta Resources, Campus Energy Partners LP
4	Does the existing feeder level metering currently measure the energy being delivered and supplied to the transmission system?	
5	Do the substations with existing feeder level metering net the delivered and supplied energy as the non-feeder metering substations do?	
6	Under AMP is the AESO installing meters to measure the energy being supplied to the transmission system?	
7	Is the AESO proposing to measure the energy being supplied to the distribution system using different feeders at the substation	
8	Example on PDF12 of the Background, does it show the issue is the method of calculation of energy flows and not the actual metering?	
9	Is it necessary to make physical changes to subs to implement AMP? Is a settlement fix an option? Reference: The Reversing PODs Discussion Paper	AltaLink Management Ltd.

AESO Response

In alignment with the *Electric Utilities Act* definitions of "transmission facility" and "transmission system", the AESO considers that the point at which feeders exit a substation to be the demarcation point between the transmission system and the electric distribution system.[1] The substation bus, switches, breakers, and transformers that feeders connect to are also considered transmission facilities per the legislated definition of “transmission facility”.

At existing substations that have meters at the feeder-level, those meters, for each specified interval, *meter* the flows to and from the transmission system on each feeder. However, under the current measurement practice, those metered amounts are aggregated in a way that results in *measured* amounts that reflect a net substation flow either to or from the transmission system for an interval. Aggregating metered amounts from feeder-level metering to reflect the net flow (i.e. the current measurement practice) produces the same measurement data as metering at the transformer level.

Under the AMP, measurement data must reflect the total energy flows of all feeders in each direction without netting. At substations with feeder metering, these flows are already metered and a change in the measurement practice aggregation is all that is required. However, at substations with transformer metering, new meters will need to be installed at the feeder connection points to have the basic energy flow data required for the AMP (where flows in both directions exist).

The example on PDF page 12 of the Section 1 Background and Ongoing Need materials shows that the AMP is a change in practice for how metered amounts are aggregated (or calculated). The intention of this example is to demonstrate how the aggregation under the AMP would change even if feeder meters were already in place. However, having feeder meters in place is a requirement to be able to produce the AMP aggregation at all.

The installation of meters at the feeder connection in a substation is the only option for implementing the AMP (subject to legacy treatment considerations). The individual energy flows into and out of a substation on each feeder are required to produce the necessary measurement data and cannot be accurately extrapolated using other metered data available to settlement, due to issues with non-interval meters, distribution line losses, unaccounted for energy, different meter data managers (MDM), and the need to use deductive totalization against the transformer meter (a practice prohibited by Measurement Canada).

Billing Determinant Erosion

Stakeholders have raised questions about the causes of billing determinant erosion and how billing determinants are impacted by the AMP.

No.	Question from AESO Engage “Share Your Questions”	Organization
10	Consider an existing DFO feeder is currently serving 15 MWs of load (i.e 15 MW, 70% LF) and at a future date a 10 MW DCG (i.e 10 MW, 80% capacity factor) is added downstream of the substation on this same DFO feeder. Would the AESO agree that the load billing determinant for this feeder and/or POC would be reduced? Would this also be BD erosion?	AltaLink Management Ltd.

[1] See AUC Decision 22942-D02-2019, *2018 Independent System Operator Tariff* (September 22, 2019), paras. 670-686.

No.	Question from AESO Engage “Share Your Questions”	Organization
11	a. Does the AESO intend to do further analysis that includes DFO substations that do not reverse flow onto the transmission system? A reverse flow on one feeder at a POD will not necessarily result in result flows onto the transmission grid and can still result in incorrect billing for the POD, as can flows that happen behind feeders.	AltaLink Management Ltd
12	Does AMP compel payment for use of existing transmission based on a larger amount of billing determinants by changing the measuring point?	Kalina Distributed Power, Signalta Resources, Campus Energy Partners LP

AESO Response

The erosion of load (i.e. DTS) billing determinants occurs if flows from the transmission system decrease, which can occur due to a reduction in load and/or an increase in generation. In the example AltaLink Management Ltd. provided in their question (noted in the table above), the addition of generation serving load on the same feeder would result in a decrease of flow from the transmission system, resulting in erosion of the load billing determinants. However, this reduction of load billing determinants accurately reflects the reduction in energy flows to the distribution system.

The AMP is not meant to address billing determinant erosion that is a result of a reduction in flows, which can also be a natural result of load and generation changing over time. It is meant to address the “artificial” billing determinant erosion that occurs under the current measurement practice when flows to and from the transmission system are underrepresented because flows through different feeders are netted against each other and cancel out. Moving from the current measurement practice to the AMP would mean that there will be more DTS and STS billing determinants for the same amount of actual energy flow, as those flows would now be accurately reflected in the measurement data.

More specifically, the AMP is not meant to address the billing determinant erosion due to a reduction of flows because load is being served by DCG on the same feeder. The AESO only provides system access service at a point of connection to the transmission system and does not provide service downstream of a point of connection to the transmission system. Notably, the billing determinants would be the same under the current measurement practice and under the AMP for this type of load reduction.

As such, the AESO does not intend to do further analysis of DFO substations that do not reverse onto the transmission system, as the billing determinants at these substations already accurately reflect the flows from the transmission system. Any reverse flows on a feeder are by name inherently flowing onto the transmission system (as the substation is part of the transmission system) and have already been considered in the AMP analysis.

AESO Annual Revenue Requirement

Stakeholder raised questions related to the recovery of the AESO's revenue requirement.

No.	Question from AESO Engage "Share Your Questions"	Organization
13	Is under EUA 100% of TFOs' yearly revenue requirement required to be recovered in addition to a 100% recovery of the AESO's own costs?	Kalina Distributed Power, Signalta Resources, Campus Energy Partners LP
14	Must each TFO's revenue requirement be recovered entirely as part of the AESO's revenue requirement for a year?	
15	All things equal, if the AESO collects 100% of its revenue requirement regardless, how will MPs pay less?	
16	If the AESO collects 100% of its revenue requirement, will some MPs pay more and some less as the same amount is to be collected?	

AESO Response

ISO tariff rates must be sufficient to recover the amounts paid by the AESO under the approved TFO tariffs and the AESO's own costs and expenses.[2] As shown on PDF page 9 of the Section 1 Background & Ongoing Need materials, under the current measurement practice, the impact of netting energy flows is that the billing determinants used for ISO Tariff billing understate the actual energy flowing to and from the transmission system. This leads to higher rates for all market participants and a misallocation of tariff costs. While the AMP does not change the AESO's annual revenue requirement and therefore the amount that all MPs pay as a whole, it changes the proportion that each market participant would pay. With implementation of the AMP, some market participants will pay more and others will pay less in a manner that better reflects their actual flows to and from the transmission system.

Applicability of AMP

Stakeholders raised questions about the applicability of the AMP and self-supply and export. At the March 23, 2023 Q&A session, stakeholders raised additional questions regarding these matters.

No.	Question from AESO Engage "Share Your Questions"	Organization
17	Is the AMP proposed to apply at all substations in Alberta or only DFO substations.	PowerAdvisory
18	Has the AESO considered whether DFOs will pursue bypass projects to mitigate the cost increases caused by AMP? 25 kV buses and switchgear could be located within either a transmission substation or an electric distribution system. The possibility of credible bypass projects would justify maintaining current substation totalization	*Versorium Energy*

[2] Section 30(2) of the *Electric Utilities Act*.

No.	Question from AESO Engage "Share Your Questions"	Organization
	policy for the same reasons the AESO maintains existing Duplication Avoidance Tariffs.	

AESO Response

The principle behind the AMP is that contracting, measurement, and billing for system access service should reflect the flows to and from the transmission system (i.e. should reflect the use of the transmission facilities). The AESO considers that this principle should apply to all market participants that receive system access service.

The AMP would not apply to market participants that are directly connected to the transmission system. However, these market participants are still required to obtain service in a manner that aligns with the principle that contracting, measurement and billing for system access service should reflect their use of the transmission system. In accordance with applicable legislation, a person is required to take service from either a DFO or the AESO, and a power plant must provide to the interconnected electric system all of the energy it generates. There are exemptions to these requirements that allow a market participant to self-supply; however, the ability to self-supply is predicated upon a person doing so without making use of the interconnected electric system.[3] Market participants that are directly connected to the transmission system and that do not self-supply must receive system access service from the AESO and the amount of service that they contract and are billed for should reflect their use of the transmission system.[4]

The legislative requirements applicable to self-supply and export decisions do not apply to DFOs since they do not "self-supply". Instead, DFOs receive system access service from the AESO in order to provide distribution service to their downstream customers. DFOs, like other market participants, can manage transmission system costs by managing their flows to and from the transmission system.

The AMP is a practice that aligns with the definition of "transmission facilities" as defined by the *Electric Utilities* Act because the AMP more accurately reflects the flows to and from the transmission system. The legislation defines the transmission facilities that must be owned by regulated transmission facilities owners.

Duplication Avoidance Tariffs (DATs) are available to market participants with Industrial System Designations that can satisfy a number of criteria relating to potential bypass and the duplication of facilities – generally, that these market participants have approval to self-supply their own on-site load with on-site generation, and there exists a "credible bypass threat" that supports them doing so (i.e., the transmission and distribution equipment that would be built by the market participant to serve the load on-site would duplicate the transmission system). Based on the credible bypass threat, these market participants could then get approval of a "bypass rate" (the DAT) for their system access service to reflect that they are using the transmission system instead of constructing the on-site transmission and distribution equipment. DATs are not available to DFOs because DFOs cannot obtain Industrial System Designations.

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[3] See Decision 23418-D01-2019 and Decision 24126-D01-2019.
[4] See Decision 24126-D01-2019 at paras. 42-43.

Future DCG and Load Growth

Stakeholders raised questions relating to the data provided in the Section 1 Background & Ongoing Need materials regarding upcoming load and DCG growth. At the March 23, 202 Q&A session, a stakeholder asked "why now" and to think about affordability impacts and potential to do this in the future where affordability may be less of an issue.

No.	Question from AESO Engage "Share Your Questions"	Organization
19	Provide the data behind the figure in Section 1, Slide 14	Lionstooth Energy
20	Dx Load Growth Reconcile the statement made in Section 1, Slide 15 "there is currently enough DCG capacity in the project list to almost double installed capacity, with little new distribution load to consume it" with statements made in the AESO's "Net-Zero Emissions Pathways Report," specifically Figure 6 (pdf page 27) that shows electrical vehicle load growth, certainty the vast majority of which will be served from the Dx system, adding over 6,000 GWh of energy by 2035.	
21	Reconcile the AESO position that it does not plan for energy supplied by DCGs, with the anticipated increased energy supply from DCG	Kalina Distributed Power, Signalta Resources, Campus Energy Partners LP
22	Why does the AESO not plan for energy delivered to the transmission system from DCG?	
23	Why does the AESO plan for energy delivered to the transmission system from BTF generation of the transmission connected generators?	

AESO Response

Please see Slide 3 of the Q&A Supplemental Information material for the background data for the DCG Production History chart.

Artificial billing determinant erosion due to the current measurement practice has kept pace with the DCG production increases and based on the AESO's Connection Project List this erosion will continue to increase for the foreseeable future. The AESO originally proposed the AMP in 2018 because of the misallocation of transmission system costs. The AESO's analysis shows that there are ways to implement the AMP with legacy treatment in a manner that limits the capital costs to implement the AMP, if affordability is a priority to address (keeping in mind that there will be tradeoffs to balance).

The statements and data on PDF page 15 of the Section 1 Background & Ongoing Need materials are based off of data from the AESO's Connection Project List of system access service requests submitted to the AESO. For PDF page 14, the AESO used data from the AESO's project list because it is a near-term view that shows the changes to load and generation that the DFO has already submitted new or amended system access service requests for (typically for within the next 3 years). The AESO's understanding of the noted 6000 GWh increase by 2035 due to of electric vehicle load growth from the AESO Net-Zero Emissions Pathways Report is that it's a *forecast* of a longer-term view based on an assumption of "high boundary of EV penetration" represented by a "policy leads, everything else follows" scenario based approach to modelling,[5] so it may not be reflective of load increases that the DFO has forecasted for or included in a request for system access service.

The AESO assumes that the word “plan” in the stakeholder questions referred to above refers to a “transmission system plan”, and that “anticipated increased supply from DCG” refers to the content on PDF page 15 of the Section 1 Background & Ongoing Need materials. The AMP is not related to transmission system planning; it is about the contracting, measurement, and billing for system access service from the transmission system. The statements on PDF page 15 of the Section 1 Background & Ongoing Need materials that there will be increased DCG in the future is based on the information from the AESO’s project list – specifically system access service requests from DFOs for new or altered service resulting from the BTF connection of new DCG.

Flow Through a Substation

Stakeholders raised questions about the use of the transmission system when electric energy from DCG flows on a feeder and through the substation.

No.	Question from AESO Engage “Share Your Questions”	Organization
24	How is the use of the transmission system changing because of measuring the energy flows at different points (at transmission feeder)?	Kalina Distributed Power, Signalta Resources, Campus Energy Partners LP
25	Which components of the transmission system the DFO is using to supply their own loads, as per PDF p 8 of the Background presentation?	
26	How is the transmission system used when DFOs use energy from DCG connected to the DFO’s system to serve needs of DFO load customers?	
27	What parts of the transmission (bulk, regional, POD) are used when a DCG energy is solely used by DFO load connected to the same DFO?	

AESO Response

Since use of the transmission system is binary (i.e., you either do or do not flow to or from the transmission system) metering and measurement only needs to reflect what enters and leaves the transmission system. The AMP does not change the measurement point or the use of the transmission system, it changes how the metered amounts are aggregated (or calculated) to separate the flows to the transmission system from the flows from the transmission system.

Consider the following simplified scenarios for flows at substations connected to an electric distribution system:

(1) DCG is located on the same feeder as load; and
(2) DCG is located on dedicated feeder(s).

[5] This means that EV projections are assumed to meet policy goals announced in the federal 2030 ERP regardless of EV availability, cost parity with non-EV choices, transmission and distribution system readiness, public and private charging optionality, regulatory, and incentives for zero-emission commercial and institutional fleet, etc.

Under the first scenario, if the DCG output is less than the load demand on that same feeder, then there would be no flow from the DCG to the transmission system, but there may be flow from the transmission system to also supply the load.

Under the second scenario, flow from the DCG would travel into the substation (i.e. POD portion of transmission system) on equipment, including but not limited to the breakers, switchgear, bus, etc. to load on other feeders. Flow from the DCG can also travel across the transformer and out the high side of the substation onto the bulk and regional portions of the transmission system.

System Access Service

Stakeholders raised a question about system access service.

No.	Question from AESO Engage "Share Your Questions"	Organization
28	a. Would the AESO agree that distribution connected load customers receive the same level of transmission service as T connected customers?	AltaLink Management Ltd.
29	Comment Response to above: Or, stated another way: As shown in the figure on Section 1, Slide 8 a series of distribution feeders with a dispatchable DCG (including natural gas fired generation and storage) ONLY make use of the 25kV transformer bus during periods when the DCG is operating. So in a situation where the DCG was running continuously, these feeders, and their associated load customers, would ONLY be using a small portion of the substation, and NONE of the radial and or bulk/regional system.	Lionstooth Energy

AESO Response

The AESO provides system access service to market participants connected to the transmission system. Distribution connected load customers receive service from the DFO of their respective service area, so the AESO is unable to speak to the level of service that they receive in comparison to a transmission-connected customer.

The AESO provides system access service on the transmission system to all market participants, including DFOs, without consideration of specifically which transmission facilities (or transmission equipment) electric energy flows across on the transmission system. This is reflected in the rates that are currently available under the ISO tariff: there is a single rate for all market participants that receive electric energy from the transmission system (Rate DTS) and a single rate for market participants that provide electric energy to the transmission system (Rate STS). Rate DTS includes bulk, regional, and POD charges that apply to all market participants that take DTS.

Price Signals and Incentives

Stakeholders raised questions about ISO tariff price signals and rate design. There were discussions at the March 23, 2023 Q&A session about whether the AMP would be irrelevant in the future if future rate design was solely based on contract capacity, and if the AESO has considered if the AMP should send locational signals to DCG.

No.	Question from AESO Engage "Share Your Questions"	Organization
30	Has the AESO considered the optimal integration of the energy provided by DCG in accordance with the AUC's Decision 26911-D01-2022?	Kalina Distributed Power, Signalta Resources, Campus Energy Partners LP
31	How will the implementation of AMP reduce sunk costs?	
32	Does the AESO consider SSF=1 only for DFOs to be a deviation of the principle of postage stamp rates? Proceeding 25848 saw the Commission approve a substation fraction equal to one ONLY FOR DFOs	AltaLink Management Ltd.

AESO Response

The AMP is not designed on its own to send price signals or provide incentives for how market participants use the transmission system, nor is the AMP about reducing sunk costs. The price signals for the use of the transmission system are a function of the rates and billing determinants that apply to system access service. More fundamentally, the AMP is about ensuring that billing determinants, and therefore bills, reflect the actual flows through the transmission system under the respective service.

The AMP will not affect the SSF = 1 interim solution that was approved by the AUC in Decision 25848. The AESO is continuing to advance tariff initiatives taking into account the guidance provided in AUC's Decision 26911-D01-2022.

During the March 23, 2023 Q&A session, there was a question regarding whether a future rate design that was based mainly on contract capacity (and therefore not require any meters or measured billing determinants) could make the AMP unnecessary. While it is possible that a future rate design may not require any meters or measured billing determinants, the measurement practice should not unnecessarily constrain the rate design. Having a measurement practice that accurately reflects the flows to and from the transmission system is foundational to rate design to ensure that bills can appropriately reflect flows to and from the transmission system.

During the March 23, 2023 Q&A session, there was a question regarding whether the AMP is meant to send a signal to DCG to avoid locating in urban areas because those substations would require the installation of new meters. The AESO discussed that it has been considered, and fundamentally, this is about how the costs for meter installations would be treated.

To add context to that discussion: If the connection of new DCG results in a DFO requesting new or amended system access, then the AESO would need to ensure that the transmission facilities in place could provide that service. Under the AMP, if the substation doesn't not have the appropriate metering in place to distinguish the flows to and from the system for the appropriate services, then transmission alterations would be required for the AESO to provide the new or amended service. The costs of installing the meters would then be participant-related costs and the determination of contribution and local investment amounts would be subject to the ISO tariff in effect at that time. The AESO considered that any contributions made by the DFO would be up to the DFO to determine.

Impact Analysis Methodology

Stakeholders raised questions about the methodology that the AESO developed to quantify the impact of the AMP on ISO tariff billing. At the March 23, 2023 Q&A session, there was discussion regarding how we arrived at the ~$16M figure that represents the billing misallocation.

No.	Question from AESO Engage "Share Your Questions"	Organization
33	Can the AESO do an impact analysis on each individual DFO POC using current billing determinants and adding back DCG interval metered data?	AltaLink Management Ltd.
34	POS Impacts Per Section 1, Slide 8, there are POS impacts too. Complete an analysis of the impact of the AMP on Rate STS.	Lionstooth Energy
35	Further Detail on Section 3 This engagement would benefit from a more detailed explanation of Section 3 (this may need to be its own session).	
36	Feeder level load data Why did the AESO not work with DFOs to obtain data of load served by each feeder in order to do a more accurate impact assessment?	PowerAdvisory

AESO Response

In order to quantify the impact of the AMP, the AESO rebilled all DTS points of connection for 2021 (including all "individual DFO POC") based on estimated billing determinants as if the AMP was in place. The AESO estimated the billing determinants by starting with the actual 2021 billing determinants and then adding back the estimated "consumed energy" and not just the DCG interval metered data. The difference is that the consumed energy accounts for the actual EDG flow out of the substation, which is over and above the total load served by the substation. After rebilling every DTS point of delivery, the AESO summed up the monthly bills for each market participant to get the total billing amount for 2021. The difference between the total billing amount for 2021 with the AMP and the total billing amount for 2021 without the AMP is shown, by market participant, on PDF 11 of the Section 3 Impact Analysis materials.

The AESO considered seeking out individual feeder information from the meter data managers for the analysis but deemed the approach to be unfeasible. A full year of data was required to cover the annual cost recovery cycle, which is a substantial amount of data when broken down to 15-minute intervals for each feeder (if this data was available at all). Analysis, provision, aggregation, and formatting of this data would create significant burden on the AESO, the MDM, and the DFO, and parties had previously expressed to the AESO the desire to minimize time and effort required for the AMP without a clear and final decision from the AUC. As such, the AESO determined that the approach taken to the indicative analysis was a prudent balance of effort and accuracy to demonstrate the range of outcomes. The AESO confirmed with Fortis that the approach taken for the analysis was reasonable and they advised that a way to check the results would be to compare the amount from our DTS impact with their annual DCG credit amount.

An analysis of the impact of Rate STS cannot be performed to the same level of detail as the Rate DTS analysis. The bill for Rate STS is made up of a single charge: **MWh X Hourly Pool Price X POS Specific**

Loss Factor. In order to perform a full analysis under the AMP scenario, the AESO's loss factor process would need to be rerun for 2021 to generate loss factors for each new POS, as well as recalculate any changes needed to the loss factor for all of the existing POS. This is a complicated and time-consuming exercise and is not practical to undertake.

However, a high-level analysis can be performed to give a reasonable approximation of the impact of the AMP on Rate STS using the average loss factor (which the loss factor process would also use for any new POS). The AESO took the hourly DCG Consumed Energy from the indicative analysis and multiplied by the hourly pool price and average loss factor (2.87%) for 2021. This represents the additional MWh under the AMP that would be subject to Rate STS charges. The result was **$4.85M** in new POS charges. As the system losses are not impacted by the AMP (the flows that cause losses aren't changing), the amount the AESO needs to collect remains the same. Therefore the $4.85M of new charges represents a misallocation of charges which would result in changes to the Rate STS bills for other market participants.

However, while the overall impact of the new POS should be close to the average loss factor, the loss factor for the Rate STS charge is specific to the location of the substation and nature of the supply (and can vary from -12% to 12%). It is not possible to tell which POS would see an increase or decrease in their loss factor, or what the magnitude of the change would be at an individual POS. For the same reason, it is not possible to accurately break down the $4.85M across the DFOs, as each DFO may vary significantly from the average.

Substation Breakdowns

Stakeholders asked for a more granular breakdown of the substations included in the Impact Analysis.

<table>
<tr><th>No.</th><th>Question from AESO Engage "Share Your Questions"</th><th>Organization</th></tr>
<tr><td>37</td><td>Can the AESO confirm that there are currently 40 subs that have reversing flows onto the transmission system today that require feeder meter
Reference: Slid 8 of Section 4, Capital Costs to Implement the AMP</td><td rowspan="2">AltaLink Management Ltd.</td></tr>
<tr><td>38</td><td>Can the AESO identify the # of subs that are not necessarily reversing flow onto transmission system but have reversing flows on feeders?
Reference: Slid 8 of Section 4, Capital Costs to Implement the AMP</td></tr>
<tr><td>39</td><td>Substation Breakdown
Produce a slide with a clear breakdown of substations, including what the following number of substations quoted in the materials refer to; 450 subs, 130 subs, 70 subs, 53 subs, plus any others missed. Also include a breakdown of substations by MP (similar to as shown in Section 3, Slide 11) with the number of subs per MP that would be impacted by the implementation of AMP.</td><td>Lionstooth Energy</td></tr>
<tr><td>40</td><td>Data by DFO service territories
Can the AESO break down the 70 substations which do not have feeder-level metering, and the 30 of those substations with reversing flows (referenced for instance on slide 8 of the "Moving Forward With the AMP" slide deck), between DFO service territories, to enable a more accurate comparison between costs and benefits?</td><td>PowerAdvisory</td></tr>
</table>

AESO Response

The AESO cannot currently determine if an individual feeder is reversing or not based on the measurement data available to the AESO. The indicative analysis used for the Section 3 and 4 materials assumed that any DCG energy being consumed on the distribution system was first being reversed into the substation, and 40 therefore reflects the number of substations with transformer metering that *may have been* reversing onto the transmission system for the analysis year of 2021. This was a conservative scenario that shows the ceiling for the number of substations that would require physical changes based on potentially existing reverse flows due to the existence of downstream DCG.

Reversing flows on feeders are inherently by name reversing onto the transmission system (as the substation is part of the transmission system), so this number is the same.

See Slide 2 of the Q&A Supplemental Material for a detailed breakdown of the substation numbers used in the analysis.

Capital Cost Estimates

Stakeholders asked about the cost estimates for installing feeder level metering at existing substations. At the March 23, 2023 Q&A session, a stakeholder asked about the costs on a per feeder basis, and there were discussions around why the AESO did not pursue cost estimates at a greater level of accuracy.

No.	Question from AESO Engage “Share Your Questions”	Organization
41	Can AESO estimate AMP costs when the necessary assessments have not been done to confirm which substations require physical changes?	Kalina Distributed Power, Signalta Resources, Campus Energy Partners LP
42	Cost Analysis The AUC’s AMP Decision was issued May 31st, 2022, around 9 months ago. The AESO’s 2023 budget for “Own Costs” is $133 million, including $5.6 million for “Contract Services and Consultants” (2023 BDP Stakeholder Presentation, Oct-2022). Given the TFOs quoted 2-6 months (leaving 3 months for further AESO analysis) and $75k (or 1.3% of the AESO’s consultant budget) to develop a AACE Class 3 estimate, why did the AESO not even do this for one substation?	Lionstooth Energy
43	Feasibility When would implementing the AMP be not technically feasible (Section 4, Slide 11)?	
44	Does implementing AMP incentivize more or less efficient use of the transmission system? AMP is proposed to address flows within substations, particularly those on 25 kV buses. How many 25 kV buses and 25 kV switchgear have been upgraded as a result of intra-substation flows identified by the AESO? For each upgrade, what proportion of the costs were paid by the system and what proportion was paid by construction contribution and investment?	Versorium Energy

No.	Question from AESO Engage “Share Your Questions”	Organization
45	$52.5m Cost Estimate I asked this at the session, but was asked to file a written question as well. The AESO noted at the session that the $750k (-50% / +100%) is a high-level estimate from TFOs for what would be the cost to install feeder level meters at an average substation and that there may be some substations where the cost could be much higher or much lower. If the TFOs provided a class 5 estimate of a "typical" substation, does that mean the total estimate of $52.5m might not be accurate to -50% / +100%? If so, can the AESO provide a more accurate range around the $52.5m? i.e. if there may be a handful of substations with significantly higher costs, should we consider the $52.5m to be accurate to +150% or +200% instead of +100%? Thanks.	PowerAdvisory

AESO Response

The AESO has provided an average, $750,000 estimate of the capital costs required to install feeder-level meters at an existing substation in an urban area. The accuracy level of the estimate (AACE Class 5, -50% to +100%) reflects that these capital projects are still conceptual. Because the capital costs would be substation-specific, developing a “per feeder” estimate or developing a more accurate AACE Class 3 cost estimate for a single substation would be misleading because the costs may deviate significantly for a substation once the substation-specific drivers are taken into consideration (such as, number of busses, yard space, the number of feeders on a bus, and the need to expand buildings and/or a yard). These substation-specific drivers cannot be estimated to a higher level of accuracy until the AESO directs a TFO to develop the capital projects and AACE Class 3 Service Proposal estimates. At this point, the AESO has not directed any TFOs to initiate these capital projects to install feeder-level metering at existing substations that currently have transformer-level metering (which would have TFOs incur the estimating costs as part of their rate-base), because implementation of the AMP has not been approved.

Section 4 - Moving Forward of the AESO’s AMP materials, at PDF page 11, should say “Based on whether changes required to implement the AMP are ~~technically~~ feasible…”. TFOs have advised the AESO that there may be some substations that would require more equipment and/or land to install feeder-level metering, which would be technically possible, but at a significant cost.

Since the $750,000 (-50%/+100%) estimate is the average for a single substation, it is also reasonable to express the total costs for all substations as a range based on the two extremes of: all costs at -50% and all costs at +100%, which would be:

Low end of range: $750k x 0.5 x 70 = $26.3M

Upper end of range: $750k x 2 x 70 = $105M

To date, the AESO has not required any substation upgrades due to intra-substation flows. All system access service requests submitted by DFOs related to the addition of new DCG have followed the AESO’s Behind-The-Fence process, with no new or amended needs approvals required.

Impact of the AMP on Market Participants

Stakeholders asked for simplified $/MWh savings and costs per customer. Discussion at the March 23, 2023 Q&A session clarified that this annual number does not have to factor in DFO rate classes and that the methodology could draw from the similar $/MWh estimations from the AESO's Transmission Rate Projection and Information Request responses in Proceeding 27047. Additionally, there was discussion at the session about how the total capital costs of implementation would be incurred (as system vs. connection project participant-related costs), which naturally led to a discussion about the cost treatment for participant-related costs.

No.	Question from AESO Engage "Share Your Questions"	Organization
46	Savings per Customer What do the savings calculated translate into in $/MWh for end-use DFO customers (Section 3, Slides 9-10)?	Lionstooth Energy
47	Cost per Customer What does the cost of implementing the AMP translate into in $/MWh for end-use DFO customers, assuming all $53 MM in costs are implemented (reference: Section 4, Slide 7)?	
48	For each of the following groups, explain the impact of implementing the AMP, with a specific focus on cost / savings; load customers, existing DCG, future DCG, DFOs, TFOs, and the AESO.	

AESO Response

Savings per Customer

The impact to DTS rates that would be applicable to all market participants, including DFOs is shown on PDF page 10 of the Section 3 Impact Analysis materials.

The results do not account for how a $/MWh impact to the DFO is translated to each DFO rate class for their end-use customers and assume the $/MWh impact to the DFOs is the same impact to the end-use DFO load customers.

The approximate simplified $/MWh DTS impact to DFO billing is the difference in $/MWh costs for 2021 billing without the AMP in place and the 2021 billing with the AMP in place. The $/MWh is the ratio of the total DTS bill amount for each DFO to the total metered energy for that DFO.

The results are:

DFO	$/MWh without AMP	$/MWh with AMP	$/MWh Difference due to AMP
ATCO	$41.27/MWh	$40.16/MWh	- $1.10/MWh
ENMAX	$42.16/MWh	$41.13/MWh	- $1.03/MWh
EPCOR	$40.53/MWh	$39.63/MWh	- $0.89/MWh
FortisAlberta	$41.24/MWh	$40.17/MWh	- $1.06/MWh

DFO	$/MWh without AMP	$/MWh with AMP	$/MWh Difference due to AMP
All DFOs	**$41.31/MWh**	**$40.26/MWh**	**- $1.06/MWh**
All Other MPs	$45.23/MWh	$44.61/MWh	- $0.62/MWh

The above table shows the simplified impact based on a single metered energy billing determinant, whereas the impact shown in the Section 3 Impact Analysis materials are based on the billing determinants for the AESO's current DTS rate design. So, for the above table, where certain DFOs ended up paying more for DTS at a total level, the difference from the table above shows a decrease in the simplified $/MWh because though the dollar amount went up, the MWh billing determinants went up by a more significant amount.

Cost per Customer

The results do not account for how a $/MWh cost to the DFO is translated to each DFO rate class for their end-use customers and assumes the $/MWh cost to the DFOs is the same cost to the end-use DFO load customers.

To approximate a simplified $/MWh cost to DFOs, assume:

- Average capital cost to install feeder-level metering at single existing urban substation is $750k (-50%/+100%)
- A "worst-case" scenario of implementing the AMP immediately with no legacy treatment (i.e. the capital projects at all 70 substations will be initiated at the same time, regardless of if they have any reversing flows at present or not)
    - The AESO does not expect that all 70 substations will actually require feeder-level metering in the future (because not all will have reversals); however, for the purposes of determining a theoretical maximum cost, the full number (70) will be used as an input.
    - This is a conservative approach because it does not factor in the timing differences that occur with capital additions to rate-base. For example, if one project energized every year starting in year X. Then, the recovery of costs for the first project would be recovered through rates as an annual amount for the years [X] to [X+40]; the recovery of the second project would be recovered in years [X+1] to [X+41], and so on. These timing differences would lead to a difference in the magnitude of total capital costs being recovered in a single year and the total number of years which the costs are recovered
    - A more realistic scenario of how capital projects are executed is that they are spread out over an extended period of time. To implement the AMP without legacy treatment would likely result in a subset of the 70 capital projects occurring within the first few years of approval, then a couple of capital projects occurring every few years. Under a more realistic scenario, there would be a more sustained cost impact to rates, but the magnitude of capital costs being recovered each year would be lower and vary over time.
- As indicated on PDF page 7 of the Section 4 Moving Forward With the AMP materials, 40 of the 70 substations currently have DCGs connected to them. Based on the conservative scenario where DCG is on a dedicated feeder, we assumed that these 40 substations already reverse. Since the installation of feeder level metering is not the result of a request for new or amended

system access service and a connection project will not be initiated, the costs for these capital projects will be assumed to be system related.

- The capital projects to install feeder-level metering at the remaining 30 substations are all occurring as part of a new request for new or amended STS. Assume that for the resulting connection projects:
  - The capital costs are classified as 100% participant-related costs
  - The interim SSF=1 solution is in place at the time of the connection projects (namely for the determination of customer contributions)
  - The current contribution policy is in place at the time of the connection project. Assume a local investment level of 60% for the connection projects
  - Any contributions made by the market participant (DFO) will be flowed-through to their customers pursuant to the DFO tariff
- Approximately 2.5% of the capital costs are recovered in a single year such that costs are collected over a 40 year time frame[6]
  - Note that this ignores the current age of the existing substation
- The total metered energy for the transmission system for 2021 was 59,014 GWh
  - Assume that this annual amount does not change for the 40 years that costs are recovered

The steps for translating the capital costs to $/MWh are:

1. For a single substation, the capital costs can be expressed as $750k (-50%/+100%), or expressed as a range of costs:

Low-end of Range	Mid-Point	High-end of Range
$375,000	$750,000	$1,500,000

2. For a single substation that has meters installed as part of a connection project, since 60% will be covered by local investment, 40% of the capital costs is required as a contribution to be paid by the market participant (DFO) to the TFO at the time of construction:

Low-end of Range	Mid-Point	High-end of Range
$150,000	$300,000	$600,000

As assumed above, the applicable DFO will determine how to flow-through the above costs to their end-customers. These capital projects will only occur in the ENMAX, EPCOR, Red Deer and Lethbridge service territories.

3. For a single substation that has meters installed as part of a connection project, the portion covered by local investment which will be recovered through the TFO's rate-base is:

[6] This follows the assumptions and rationale in Exhibit 27074-0081, AESO-LEI-2022MAR28-008.

Low-end of Range	Mid-Point	High-end of Range
$225,000	$450,000	$900,000

4. For a single substation that has meters installed as part of a system project:

Low-end of Range	Mid-Point	High-end of Range
$375,000	$750,000	$1,500,000

5. For a single substation, if 2.5% of the capital costs are included in the TFO's revenue requirement each year (for 40 years):

Type of Project	Low-end of Range	Mid-Point	High-end of Range
Connection Project	$5,625	$11,250	$22,500
System Project	$9,375	$18,750	$37,500

6. Based on installing feeder-level metering at all 70 existing substations, for each year (for 40 years):

Type of Project	Low-end of Range	Mid-Point	High-end of Range
Connection Project (40)	$168,750	$337,500	$675,000
System Project (30)	$375,000	$750,000	$1,500,000
All Substations (70)	$543,750	$1,087,500	$2,175,000

7. The ISO tariff recovers all TFO revenue requirements over the total billing determinants for the system. For all 70 substations, based on 59,014,321 MWh of metered energy for each year (for 40 years):

Low-end of Range	Mid-Point	High-end of Range
$0.01/MWh	$0.02/MWh	$0.04/MWh

Impact By Group

The table below summarizes the impacts of implementing the AMP on different groups, assuming that the implementation of the AMP is approved without legacy treatment.

	Capital Cost Impact	ISO Tariff Bill Impact
AESO	Increase in the number of connection projects requiring transmission alterations, so revenue requirement would increase.	Billing determinants more accurately reflect flows to and from the transmission system.

	Capital Cost Impact	ISO Tariff Bill Impact
Dx-connected load	The DFO that provides service to the end-use customer could see capital costs and DTS billing impacts. The DFO would then pass on the costs and impacts to their end-customers per the DFO tariff.	
Tx-connected load	No capital cost impact.	DTS rates are lower for all market participants. This is a due to the higher billing determinants for the system, which could be slightly offset by the increased TFO revenue requirement if the costs to install feeder-level metering are included in the TFO rate base.
Rural DFOs	No capital cost impact as the work required to implement the AMP would be administrative in nature.	DTS rates are lower for all market participants. This is a due to the higher billing determinants for the system, which could be slightly offset by the increased TFO revenue requirement if the costs to install feeder-level metering are included in the TFO rate-base. At a DTS billing level, even though DTS rates are lower, if the DFOs billing determinants have increased due to the AMP, then they will pay DTS on those incremental billing determinants. At an STS billing level, there will be more points of supply, so DFOs would have more STS bills – the magnitude of impact to each DFO won't be known until POS-specific loss factors are modelled.
Urban DFOs	For substations with existing reverse flows, no capital cost impacts as long as the principle that costs can't retroactively be applied to market participants is upheld. For substations with reverse flows in the future: connection projects will be required as a result of the DFO request for new or amended system access service. DFOs may be required to pay a contribution towards the participant-related costs depending on the amount of local investment provided.	Same as Rural DFOs.

	Capital Cost Impact	ISO Tariff Bill Impact
Existing DCG	None, as long as the principle that capital costs can't retroactively be applied to market participants (including DCGs) is upheld.	Impact to DFO STS bills will impact downstream DCG. There will be more STS' therefore, more DFOs will see a STS charge/credit that will get flowed-through to the downstream DCG. The increase in upstream DFO DTS bills will mean DCGs currently receiving a DCG Credit will see that credit reduced if the AMP is implemented while the DCG credit mechanism is still in place.
Future DCG	If new DCG is connecting to a substation resulting in the DFO requiring new or amended system access service, and that substation requires the installation of feeder-level metering in order for the AESO to provide the new or amended system access service, then the DFO will make a contribution towards the participant-related costs. Then, it would be up to the DFO to determine how to pass on those costs to DCGs per their tariff.	Same as Existing DCG.
TFOs – rural DFO service area	No capital cost impact as the work required to implement the AMP would be administrative in nature.	None – TFOs do not pay for SAS.
TFOs – urban DFO service area	If a connection project to install feeder-level metering is required for the AESO to provide system access service at a substation, then the TFO would be directed to execute the projects. The TFO would recover the capital costs of the projects through a combination of contributions made by the market participant (DFO); and through their TFO rate base (for any local investment portion).	None – TFOs do not pay for SAS.

Conclusions from Cost-Benefit Analysis

Stakeholders raised questions about the outcome and conclusions from the AESO's analysis of costs and impact. At the March 23, 2023 Q&A session, there was discussion about how the $16M (misallocation) figure should not be referred to as a "benefit", about ways to implement the AMP without incurring costs, and how this cost-benefit analysis isn't a "conventional" analysis.

No.	Question from AESO Engage "Share Your Questions"	Organization
49	$16m cost shifting Is the $16m per year shown in slide 8 of the "Moving Forward With the AMP" slide deck is the amount of money that would be shifted annually from one set of ratepayers to another, consistent with the information shown in slide 11 of the impact deck?	PowerAdvisory
50	Implement the administrative solution and wait. Implement the administrative solution and wait on the metering decision until the "future" Tariff becomes clearer.	IPCAA

AESO Response

In AUC Decision 27047-D01-2022, the AUC directed the AESO to quantify the benefits of implementing the AMP. The primary benefit of the AMP is that it allows for billing and billing determinants that more accurately reflect each market participants flows to and from the transmission system. This results in lower rates for <u>all</u> market participants.

From an individual market participant perspective, the re-allocation of costs would result in some market participants paying more, and others paying less, so AMP implementation would not result in a financial benefit to all market participants. Because of this, the AESO agrees that the $16M figure from slide 11 the Section 3 Impact Analysis and slide 8 of the Section 4 Moving Forward with the AMP materials cannot simplistically be framed as a "benefit" (since some market participants will, in total, pay ~$16M more, and others market participants will, in total, pay ~$16M less). As such, the AESO will refer to the re-allocation of bills as an "impact" of the AMP.

To elaborate on the AESO's comments about how the cost-benefit (or more appropriately, "cost-impact") analysis isn't a "conventional" analysis because there are other principles and tradeoffs to consider:

- The analysis shows an asymmetry in how most of the costs and benefits of the AMP would be realized – the costs that are incurred by one party lead to a financial benefit to a different party.
- Additionally, there are intangible benefits that aren't quantifiable and may not be a financial benefit from the narrow perspective of a single market participant, but would still be a benefit for the system as a whole because the misallocation is eliminated.

The AESO does not consider that a cost impact analysis is necessary to justify *whether or not* the AMP should be implemented, it is useful to support or guide *how the AMP should be implemented* (for example, with our without legacy treatment). A natural starting point for ISO tariff billing is that measured outputs accurately reflect the flows to and from the transmission system for the applicable service, so market participants can be billed based on accurate billing determinants. Then, in *limited* cases where there are reasons to deviate from that principle, the cost-impact analysis would be a useful tool to guide when deviations from that natural starting point would be reasonable.

The results of the AESO's cost-impact analysis show that most capital costs to fully implement the AMP are localized to a subset of substations. The results also show that most of the significant billing impact is localized to a small number of market participants. Slide 9 of the Section 4 Moving Forward With the AMP materials shows that 93% of the consumed energy was at substations that would only require administrative work to implement the AMP. While this is not an exact proxy, it can reasonably be assumed that the share of the billing impact would be the approximately the same. As discussed at the March 23rd Q&A session, the analysis shows that there is a way to implement the AMP in order to realize a majority of the benefits while limiting costs if legacy treatment is provided to certain substations.

Upcoming AUC Application

Stakeholders raised questions about the timing of the AESO's upcoming application to the AUC for the AMP, along with the content that would be included in that application. At the March 23, 2023 Q&A session, there was discussion about whether cost treatment details would be premature and if they should be included in the application, at least at a high-level. There were also questions around when the AESO expects the AMP to be effective.

<table>
<tr><th>No.</th><th>Question from AESO Engage "Share Your Questions"</th><th>Organization</th></tr>
<tr><td>51</td><td>Timing
There are 11 working days between when comments are due, and the AESO's proposed filing deadline. Is the AESO even considering changes to their AMP proposal based on stakeholder feedback?</td><td>Lionstooth Energy</td></tr>
<tr><td>52</td><td>How is the proposed AMP different from the AMP proposal submitted in Proceeding 27047, which was ultimately rejected by the AUC?</td><td rowspan="2">Kalina Distributed Power, Signalta Resources, Campus Energy Partners LP</td></tr>
<tr><td>53</td><td>Are immediate changes to implement the AMP limited to substations that only need administrative changes fair to DFOs with different cost?</td></tr>
<tr><td>54</td><td>The AESO noted at the consultation session that it doesn't want to discuss cost treatment at this time, but rather plans to leave that topic to an implementation compliance filing after AMP is approved by the Commission. Can the AESO confirm it does not intend to apply any retroactive connection charges that may be applicable to DCGs already past their final investment decision? The AESO suggested at the session that it may be willing to add this principle to its AMP application. Please confirm this willingness. Thanks.</td><td>Power Advisory</td></tr>
</table>

AESO Response

The AESO has adjusted the schedule for comments and filing, as noted in the materials posted for and discussed at the March 23, 2023 Q&A session. The AESO has amended the schedule to include more time for engagement and is targeting to file in May depending on the feedback received.

In AUC Proceeding 27074, the AESO proposed an implementation plan for the AMP based on the AUC's direction to implement the AMP without legacy treatment. The AUC rejected that plan and questioned if the AMP should be implemented given the AUC's approved phase-out of DCG credits.

In its upcoming application to the AUC, the AESO does not intend to file an AMP implementation plan. The AESO intends to first file an application to confirm the AUC's approval of the AMP and, if that confirmation is provided, to obtain confirmation from the AUC of whether the AMP should be implemented with or without legacy treatment.

In its upcoming application, the AESO will provide its rationale for the AMP as laid out in the materials in Section 1 Background & Ongoing Need and Section 2 DCG Credits and the AMP. The AESO will also provide the Impact Analysis to show the costs associated with implementing the AMP at the different types of substations and the impact to each type of market participant if the AMP is implemented.

As discussed at the March 23, 2023 Q&A session, there are considerations and tradeoffs that the AUC should weigh when deciding which path to take (not moving forward with implementing the AMP; implementing the AMP without legacy treatment; or implementing the AMP with legacy treatment). Additionally, if the AUC confirms that the AMP should be implemented, then the AESO could request guidance from the AUC regarding the objectives to prioritize and principles that should guide implementation.

As part of the application, the AESO intends to provide considerations and tradeoffs that it believes the AUC should take into account. Some considerations and tradeoffs that would be included (and further elaborated on) are:

- The timing of implementation, including when it should start and if a "deadline" should be considered.
- If and how the timing differences between implementing the AMP at substations that only require administrative changes and substations that require physical changes should be considered.
- Whether there should be a "maximum capital cost" or "maximum annual capital cost" for any physical changes required to implement the AMP.
- How capital costs should be treated for existing substations that already have reversing flows but would require a retrofit to install feeder-level metering.
    - Note that these retrofit projects would not be initiated as a result of a request for new or amended supply transmission service because the DFO has already been receiving that STS service.
- How capital costs should be treated for metering retrofits at existing substations that develop reverse flows in the future.
    - These costs would be incurred as the result of a request for new or amended supply transmission service from the DFO because the reversal had not previously existed.
    - The interim substation fraction = 1 would make these participant related costs eligible for investment. The AUC should consider if eligibility for investment should still be the case if/when SSF = 1 is no longer in place.
    - The flow-through of contributions made by DFOs for the remaining participant-related costs is a DFO tariff matter so the AESO will not be determining what portion of the metering retrofits should be paid by a DCG vs other DFO customer.
- The impact of the AMP on DCG credit amounts, taking into account the timeline for AMP implementation and the approved phase out of DCG credits.
- If the AMP is not implemented, the inconsistency that will persist between how DFOs and non-DFOs contract and are measured and billed for system access service, and how these inconsistencies impact TCG vs DCG.

- If the AMP is implemented with legacy treatment, the resulting inconsistency between how DFOs contract, and are measured and billed for system access service, and how these inconsistencies impact DCG located in different DFO service areas.
- How the addition of DCG does not necessarily result in flows into a transmission substation, namely if the DCG is only offsetting load on the same feeder. DFOs can manage DCG and load flows to prevent reversals onto the transmission system:
    - For example, by limiting the amount of DCG on each load feeder; operational measures to transfer load between feeders; or physical/operation measures to prevent flow into the transmission system.
    - Preventing flows into the transmission system at substations that do not have feeder-level metering to meter those flows is a way to avoid metering retrofits (and capital costs).
- If the AMP is approved with legacy treatment, the criteria for legacy treatment, and the appropriate length of time for legacy treatment (i.e. how long should they be provided legacy treatment).
- Connection project costs that may be flowed to DCG resulting from locating at a substation that requires transmission alterations (for example, installation of feeder-level meters) in order to receive SAS.
- Consideration for the Measurement System Standard.

As already noted above, the AESO also considers that, if the AMP is approved with or without legacy treatment, it would helpful if the AUC were to confirm the principles that should be used to frame AMP implementation. The AESO considers that the following principles may be appropriate:

- As discussed in Decision 25848-D01-2020, connection costs should not be allocated to DCG after they have made their final investment decisions.
- As discussed in Decision 25848-D01-2020, the costs that a DFO flows through to DCG is a matter best addressed in the DFO’s tariff.
- If the AMP is approved, there will be no retroactive billing of Rate DTS and Rate STS bills for any market participant.

The AESO has amended question 6 of the Stakeholder Feedback Questions on AESO Engage to solicit feedback regarding the considerations and tradeoffs that stakeholders believe should be addressed in the AESO’s upcoming application.

Appendix I – Q&A Session Attendees

Organizations that attended the March 23, 2023 AMP Q&A session:

Organization
Alberta Direct Connect Consumers Association (“ADC”)
Alberta Utilities Commission (“AUC”)
AltaLink Management Ltd.
ATCO Electric
Campus Energy
Capital Power
Chymko Consulting
City of Red Deer
Competition Bureau
ENMAX Energy
ENMAX Power Corporation
EPCOR Distribution & Transmission Inc
Evolugen
FortisAlberta Inc.
Independent Consultant
Industrial Power Consumers Association of Alberta (“IPCAA”)
Lionstooth Energy
Power Advisory LLC
TransAlta Corporation
The Office of the Utilities Consumer Advocate (“UCA”)
Versorium Energy Ltd.

Appendix II – Participant Organizations

The following organizations participated at the March 23, 2023 AMP Q&A Session, as well as through the AESO Engage Idea Board:

Organization
AltaLink Management Ltd.
Industrial Power Consumers Association of Alberta ("IPCAA")
Lionstooth Energy
Power Advisory LLC (on behalf of DCG Consortium)
TransAlta Corporation
Versorium Energy Ltd

AMP Engagement

Q&A Supplemental Information

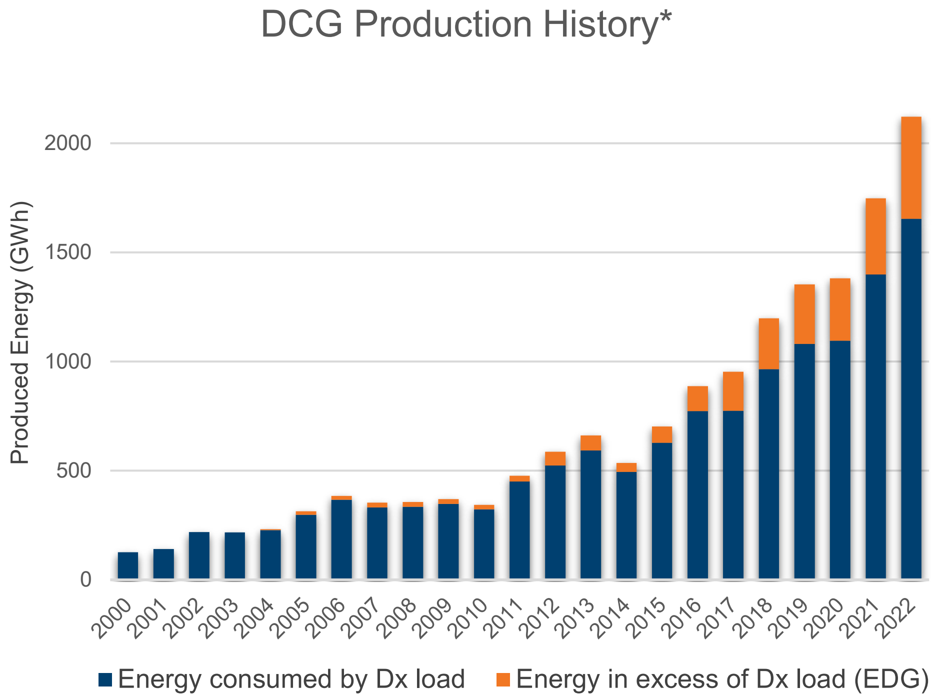
Impact Analysis Substation Information

This table contains the breakdown of the substations used in the Impact Analysis and Moving Forward With The AMP material.

Category	Metering	Total	"Rural" Substations		"Urban" Substations			
			Fortis/AML	ATCO	ENMAX	EPCOR	Red Deer	Lethbridge
Transmission substations serving electric distribution systems		**450***						
These are the "DFO substations" that fall under the scope of the AMP for the 2021 indicative analysis	Feeder	380*	242	147				
	Transformer	70*			38	24	4	6
Substations without downstream interval metered DCG production		**320***						
These substations do not have any reversing flows, but would be impacted by the AMP if any reversals materialized at some point in the future	Feeder	290*	176	123				
	Transformer	30*			12	11	3	6
Substations with downstream interval metered DCG production		**130**						
These substations were assumed to have all DCG production reversing into the substation and would therefore be impacted by the AMP	Feeder	90	66	24				
	Transformer	40			26	13	1	0
Substations with reversing PODs / EDG Flows		**43**						
These substations fully reversed onto the bulk and regional Tx system and needed to have their POS MWh subtracted from the DCG production for the analysis	Feeder	42	35	7				
	Transformer	1			1	0	0	0

**The number of substations for each DFO is based on billed SAS agreements, and can include substations with multiple agreements, substations totalized under a single agreement, and substations serving an industrial facility under section 101(1) of the EUA. The totals were therefore reasonably decreased in the material to better reflect the actual number of substations serving distribution systems, and will be slightly lower than the individual DFO counts in the table.*

DCG Production History with Source Table



*Includes all interval metered DCG and large micro-generation

Year	DCG Settled Volumes	EDG Settled Volumes	"Consumed" Energy
2000	127	0	127
2001	142	0	142
2002	219	0	219
2003	217	0	217
2004	233	4	229
2005	315	16	299
2006	385	18	367
2007	354	22	332
2008	357	21	335
2009	370	22	348
2010	344	21	323
2011	477	27	451
2012	587	63	524
2013	662	69	593
2014	536	42	494
2015	702	74	628
2016	887	115	773
2017	953	179	774
2018	1199	233	966
2019	1355	274	1081
2020	1382	285	1097
2021	1748	348	1400
2022	2122	468	1654

Survey Responses

6 March 2023 - 21 April 2023

Request for Feedback | Continued Need, Benefit & Approaches Consultation March 6-April 21, 2023

AESO Engage

Project: Adjusted Metering Practice

BANG THE TABLE engagementHQ

Respondent No: 1 **Responded At:** Mar 30, 2023 15:37:25 pm
Login: ENMAX-Rose-Ferrer
Email: rferrer@enmax.com

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

ENMAX Corporation ("ENMAX") does not support the approval and implementation of the AMP at this time. In our view, the cost to implement the AMP would significantly outweigh any perceived benefits noted by the AESO, and as such, there does not appear to be a strong enough case for change. We would like to see the AESO revisit the cost assumptions to understand the total scope of effort and costs that would be required and then assess whether ratepayers would benefit from any changes to the measurement practices.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

The billing determinant erosion on rates and cost allocation is a bigger issue that should be considered as part of the AESO's tariff evolution initiative which just kicked off in February. A future tariff may or may not benefit from changes to the measurement practices.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

See response to Question 4.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

ENMAX remains concerned with the lack of accuracy on both the AESO's impact analysis and cost estimates. Given the existing economic climate and other priority initiatives on the horizon, ENMAX does not believe the AMP should be pursued at this time.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

In general, if the AMP were to proceed, there would have to be a clear case for demonstrating that the benefits to ratepayers would outweigh the implementation costs. As noted in our response to Question 1, ENMAX does not support implementing the AMP given these benefits have not been proved out by the AESO. If this were to move forward, ENMAX would require the flexibility to implement the program based on its own timeline, allowing us to consider the needs of our transmission and distribution system (and customers), along with the overall lifecycle of our current assets. Regulated entities would also require clear direction from the AUC instructing us to move forward with the metering upgrades, and certainty around the treatment of the stranded assets that would be created with implementing the AMP.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

See responses above. Minimizing costs to implement the AMP should be a key principle in determining whether the initiative should move forward or not.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.** not answered

Respondent No: 2 **Responded At:** Apr 17, 2023 14:26:57 pm

Login: cclturner

Email: turner@chymko.com

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

The Cities of Lethbridge and Red Deer do not support the implementation of AMP because the AESO has not adequately demonstrated that AMP is the most effective and appropriate response to the problem of billing determinant erosion. There is no indication that the AESO has considered any potential alternatives. Given that AMP implementation is projected to cost upwards of $52 million, the Cities believe serious consideration should be given to more direct and cost-effective potential solutions, such as using billing determinants that do not erode as easily. For example, the Cities note that a demand charge with a longer rachet is a billing determinant that does not easily erode. The AESO’s own analysis confirms this. Slide 9 of the Impact Analysis shows that billing capacity for DTS – Regional System charge, which is based on ratcheted demand, changes by only 0.2% with the theoretical implementation of AMP. In other words, with or without AMP, this billing determinant virtually stays the same. This indicates that if more DTS charges (specifically the Peak Demand Charge) were based on ratcheted demand, it would better capture how the system is used without requiring investment in otherwise unnecessary meter infrastructure.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO’s current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

The Cities of Red Deer and Lethbridge do not agree. The AESO has not demonstrated that billing determinant erosion is due to the current measurement practice. Billing determinant erosion happens when there are improper billing determinants for the situation, not because of a lack of metering. This is not a new or novel issue for distribution utilities. We have always had to consider how to fairly bill and recover the cost of intermittent loads without expending disproportionate resources on metering. Arguably the cause of intermittent load (i.e., distribution connected generation) is a new phenomenon, but the impact is the same for planning, reliability and system capacity. The AESO’s Engage documents clearly state that the point of AMP is to address the erosion of billing determinants. However, in the Q&A session, when alternative options to address billing determinant erosion (such as basing rates on billing capacity with a penalty for going over) were suggested, the AESO responded that they consider the issue at hand to be a metering and measuring issue and that the question of installing meters is “foundational.” If the issue to be addressed is billing determinant erosion, then the AESO ought to consider tariff solutions that do not cost $50-100 million dollars. If the issue is that the AESO wants to install revenue meters for the sake of something more “foundational,” then the AESO needs to define what that means and explain why the meters in and of themselves are a benefit to the transmission system, and how their $50-$100 million-dollar cost is justified.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

The Cities of Red Deer and Lethbridge do not agree that the current metering practice is the root cause of billing determinant erosion. As such, any impact analysis should also consider alternative approaches to addressing billing determinant erosion, such as using billing determinants that erode less easily.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

The Cities concern with using existing capital cost oversight mechanisms is that it delays assessing the cost of AMP until after the AMP has been approved. This timing effectively defeats the purpose of a cost-benefit analysis because once AMP is approved, it would be very difficult to change course regardless of the cost of the meters. The Cities position is that the AESO should pursue a more direct, efficient, and cost-effective rate design solution to address billing determinant erosion. However, if the AESO believes there is value in installing revenue meters and that this is the best solution for billing determinant erosion, then there should be a thorough cost-benefit analysis, as directed by the Commission in Decision 27047-D01-2022.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

The Cities of Red Deer and Lethbridge do not support implementing AMP. If it is implemented with legacy treatment, the AESO will have to address concerns that it is unduly discriminatory because it treats otherwise identical customers differently depending on whether they are served through a substation that is subject to AMP.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

The Cities of Red Deer and Lethbridge do not support implementing AMP. We have seen no analysis to indicate that it can be implemented in a manner that minimizes costs, particularly because the costs have not been adequately assessed. As DFOs, the Cities are concerned about the potential costs associated with installing revenue meters, as these will ultimately be passed on to customers. The Cities further note that our distribution connected generation customers are already metered at their premises. A second set of meters at the other end of the same feeder is a costly and unnecessary duplication of infrastructure. As TFOs, the Cities are concerned about having to spend time and resources installing revenue meters when these do nothing to enhance service, capacity, or reliability.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.**

not answered

Respondent No: 3
Login: ADC-Colette-Chekerda
Email: colette@carmal.ca

Responded At: Apr 19, 2023 11:50:29 am

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

The ADC does not support the implementation of the AMP. The proposed method to address the billing determinant erosion concern is costly and does not have commensurate benefits to Alberta ratepayers. This issue can best be addressed with DTS tariff design.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

It does need to be addressed, but the issue originates with the tariff design, and not the metering practice. If the DTS tariff were designed for firm and non-firm capacity, then there would be no billing determinant erosion at the Distribution POD's as they all would be paying based on a firm load commitment. The firm load commitment would not be impacted by DCG's unless they could reliably serve the firm load behind the POD 100% of the time. Any energy billing determinants in the tariff are legitimately offset by a DCG and those should not be disregarded for POD billing purposes.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

It seems the solution will result in more issues than the problem being addressed. The AESO resources would be better spent on working through a firm and non-firm tariff design that addresses these concerns in a sustainable way.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

Historically, cost estimates have been lower than actuals, so ratepayers should expect higher rates overall if this proposal moves forward. Ongoing O&M costs, Utility returns, data warehousing, administration, and billing costs will make this much more costly than anticipated.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

Do not support.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

To reiterate, this concern can be solved through DTS rate design. The AESO has been given an opportunity to thoughtfully approach the tariff re-design to address this issue and others. The tariff should be designed to reflect the value of the service and to ensure fair treatment of different types of users of the grid.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.**

not answered

Respondent No: 4 **Responded At:** Apr 20, 2023 10:04:17 am
Login: IPCAA
Email: richard.penn@ipcaa.ca

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

IPCAA appreciates the analysis undertaken by the AESO it is extensive, isolating both costs and benefits. IPCAA agrees with the principle of Causer pays. The AESO has identified 16M$/ year of misallocating user costs from Distribution Connected Generators (DCG) to other connected loads. The misallocation occurs annually and indefinitely if an adjusted metering practice (AMP) is not implemented. IPCAA welcomes any reduction in misallocated charges to its members and concurs with the market principle of causer pay. The AESO, in its analysis, identified two potential options to reallocate the 16M$ across market participants: A. Administrative Changes – 90 of the 130 substations in the impact analysis would only require administrative changes to implement. The AMP would incur no capital costs and would capture 93% of the 16M$ in misallocation - 14.9M$. B. Capital Costs - Installing feeder metering (40 substations) at approximately 30M$ - 50 M$. On the recent call, there was a discussion that this may not have been an accurate estimate and the price could be as high as double 60M$ - 100M$ IPCAA supports the implementation of the AMP but suggests that such an implementation be staged. Stage 1: AESO will undertake the administrative changes that would capture the vast majority of the misallocation, 93% (14.9 M$). Stage 2: The AESO will undertake a cost/benefit analysis to determine if capturing the remaining 7% of the misallocation ($1.2 M) would be beneficial by expending capital dollars. • Cost / Benefit Analysis of undertaking administrative changes to implement the AMP rather than revenue meter installations.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

Yes. An underlying market principle in the Alberta electricity market construct is causer pays. The AESO has identified 16M$ of annual misallocation of user costs that need to be allocated to the causer.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

No opinion

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

Based upon a C/B analysis, undertaking the capital costs/metering or even better estimates of those costs may not be worthwhile. The AESO should make that assessment assuming the Administrative Changes have reduced misallocation by 93%.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

At this stage, it would seem best to make the administrative changes and not physical changes to the remaining substations. (Legacy Treatment). If in the future a substation had reverse flows or if the reverse flow increased, at that point, a physical change (metering) would be emplaced (capital cost).

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

Yes. It would be worthwhile waiting on the solution of installation of revenue meters until the future AESO tariff is better understood. Dependent on the revised tariff, revenue meters may not be the solution.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.** not answered

Respondent No: 5 **Responded At:** Apr 20, 2023 15:19:50 pm
Login: cclturner
Email: turner@chymko.com

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

The University of Alberta does not support the approval and implementation of AMP because it results in substantially higher charges for the University even though the University is not using the transmission system in a way that contributes to the erosion of billing determinants. The University operates within its own defined service area, interconnected to the transmission system via six dedicated EPCOR Distribution feeders to the Garneau substation. The University is a net consumer of energy from the provincial transmission system, but also supplements part of its energy needs via an integrated district energy system that pre-dates the current Electric Utilities Act. At a conceptual level, the University's generation source is located in the University service area and all energy is consumed in the same service area. The University actively manages its system to ensure that energy is not exported to the rest of the EPCOR Distribution system. Nonetheless, AMP would result in the University being charged as though the energy that is moved from one part of the distribution system to another (albeit through EPCOR feeders) is in fact being exported to and drawn from the provincial transmission system. In this sense, AMP artificially inflates the EPCOR Distribution's billing determinants. If AMP is implemented, the University's options are limited and, in our opinion, not in the public interest: 1. Bypass EPCOR's feeders with additional distribution infrastructure: This is a duplication of infrastructure because the current technical solution was and is considered the most efficient and least cost. The University has a limited budget for capital projects, and this option means that scarce resources will have to be diverted away from other necessary infrastructure projects. 2. Modify generation patterns and keep energy production on one side of the campus to avoid wheeling energy through the EPCOR feeders. This would result in the University having to purchase more expensive energy from the power pool rather than generating power on site. In addition to costing the University money, this would lead to an increase in greenhouse gas emissions. 3. Business as usual / do nothing, which will add millions to the University's DES energy expense and divert resources away from the primary purpose of the DES users of teaching, research, community engagement, and medical services. It is important to note that despite the significant cost to the University, both in terms of dollars and opportunity costs, there is no benefit to transmission customers. The implementation of AMP at the Garneau substation would do nothing to address the erosion of billing determinants. It only artificially inflates the University's billing determinants, and depending on how the University responds, the billing determinants at the Garneau substation could return to what they were before AMP.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

This proposal is not a fair or effective way to address billing determinant erosion. Billing determinant erosion may be an issue that the AESO must address, but AMP results in disproportionate costs for the University's DES by artificially inflating the University's billing determinants. More importantly, we see no evidence that the AESO has given due consideration to any alternatives that do not involve the cost and unintended consequences of AMP. For instance, the AESO does not appear to consider that changing the billing determinants is a reasonable option. Slide 9 of the AESO's impact analysis already indicates that some billing determinants in the current rate structure are not eroding to the same degree. Billing determinants for EPCOR's distribution feeders were likely designed with this same issue in mind more than twenty years ago and our bill from EPCOR for use of distribution facilities does not change based on the direction of energy flow. These same distribution feeders connect to the switchgear at the substation and all the University's generation is wheeled back to the University's service area. If the lack of a revenue meter inside the substation fence was the underlying problem, then billing determinant erosion would also be an issue for EPCOR distribution. However, it is not because EPCOR uses a more robust billing determinant that does not erode.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

The University is unable to provide any further insights, given the University's fundamental disagreement with the AESO's approach to billing determinant erosion.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

No comment.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

We do not support implementing AMP, but if it is implemented, the University grudgingly supports legacy treatment. Besides incorrectly implying that the University is receiving special treatment, legacy treatment is not permanent and can be discontinued without warning, as the experience with Decision 25848-D01-2020 demonstrated. Regardless of the position the AESO takes on legacy treatment, the University requires better and more direct communication as to: • Whether the Garneau substation is included in the list of 40 substation that require physical changes and might therefore be eligible for legacy treatment. • The conditions under which the AESO would recommend withdrawing legacy treatment. • When AMP will be implemented. The impact of AMP on the University is of a magnitude that advance planning is necessary.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

The University does not support the implementation of AMP. The AESO has not demonstrated it has considered alternatives that do not require additional capital infrastructure.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.** not answered

Respondent No: 6 **Responded At:** Apr 21, 2023 09:22:42 am
Login: PowerAdvisory-Christine-Runge
Email: crunge@poweradvisoryllc.com

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

This response is a joint submission by BluEarth Renewables Inc., Elemental Energy Renewables Inc., and RWE Renewables Canada Holding Inc. (the “DCG Consortium”). This submission represents the consensus view of the group and is submitted on behalf of the group by Power Advisory LLC. The DCG Consortium does not support approval and implementation of the AMP. The AMP is unnecessary to address the issue of billing determinant erosion (see response to question 2). Further, the AESO’s “cost benefit analysis” does not identify any real costs to aggregate ratepayers of the ISO tariff of not proceeding with the AMP and does not quantify the dollar value of benefits associated with reducing or eliminating the identified misallocation. The DCG Consortium supports the AESO’s recharacterization of this work as a “cost impact analysis” as it measures the value of misallocation. As acknowledged by the AESO in recent consultation, the $16m/year in annual misallocation identified on the slide titled “The Total Costs and Benefits of Implementing the AMP”, in the “Moving Forward With the AMP” slide deck, is not a “cost” to net transmission customers (and accordingly, preventing $16m/year in misallocation does not result in a $16m/year “benefit”). Rather, it quantifies the amount of money that would be shifted annually from one set of ratepayers to another. While cross subsidization and inefficiently high tariff rates can cause a cost to customers, the AESO has not highlighted or attempted to quantify any such costs. The “misallocated” $16m/year would be collected from different customers with the AMP than without it, but on net, the total cost to transmission customers would be the same. Meanwhile, the $30m - $52.5m cost of implementing AMP is a real cost that will increase the total annual transmission revenue requirement to be collected from customers. The AESO should be approaching this, and all other major transmission policy matters, with consideration for affordability (including the potential for negative investor certainty impacts that ultimately increase customer costs) and impacts on the fair, efficient and openly competitive operation of the electricity market. Accordingly, amongst other considerations, if the AESO cannot identify a real cost to ratepayers of not implementing the AMP that is greater than at least $30m, if not $52.5m or $105m (as discussed below), then the AESO should not proceed with its application for the AMP implementation. It particularly should not do so in a form that preferences some generators over others and is thus discriminatory. The DCG Consortium also suggests that the time and effort that would be invested in AMP approval and implementation (including the regulatory proceeding and other implementation efforts) could be better spent on higher priority issues such as advancing an energy storage tariff module which was recently identified as a priority issue by stakeholders at the Tariff Evolution Roundtable & Work Café held on February 14, 2023, or other key issues such as system vs participant costs, which is an issue currently creating an unlevel playing field between generators. Lastly, the DCG Consortium suggests it may be more prudent to proceed with the AMP after the resolution of the bulk and regional tariff design. The next ISO tariff application may include rates that are almost fully fixed (in response to Decision 26911-D01-2022). Accordingly, the benefit of implementing the AMP will fall significantly. Any ISO tariff that bills based on either a fixed monthly per site fee or an NCP charge that includes a 12-month ratchet rate, such as the current NCP rate design, will not result in billing determinant erosion due to any DCG that needs to go down for either planned or unplanned maintenance at least once a year or due to any DCG with a variable fuel source that isn’t operating at maximum capacity in all hours. Given that the next tariff design could render the AMP unnecessary, it is imprudent for the AESO to spend as much as $105m in ratepayer money to address its outlined concerns. The AESO should instead wait until its next ISO tariff is approved and then re-assess at that time if it continues to consider there to be measurable benefits from the AMP. If so, it should re-start this consultation at that time with an updated cost-impact analysis. The AESO’s assertion that “the measurement practice should not unnecessarily constrain the rate design” is not sufficient justification for the capital outlays and other negative impacts of AMP implementation. Any necessary changes to the measurement practice can follow any approved changes in rate design to the extent they are required.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

This response is a joint submission by BluEarth Renewables Inc., Elemental Energy Renewables Inc., and RWE Renewables Canada Holding Inc. (the "DCG Consortium"). This submission represents the consensus view of the group and is submitted on behalf of the group by Power Advisory LLC. A minuscule amount of the total transmission revenue requirement is attributable to the cost of feeders on substations. The AESO is looking to add into the accounting of billing determinants, for the purposes of charging out the total transmission revenue requirement, the power that flows across only feeders without making use of any other transmission infrastructure. The additional MWs are not contributing to the cost of or benefiting from the existence of the vast majority of transmission infrastructure. Given that the AESO is only proposing to apply the AMP to DFO substations, then the issue highlighted by the AESO in this question is no different from the impact of any other behind the fence generation and is arguably positive for the transmission system. Load is receiving power with less reliance on the transmission system, freeing up transmission capacity for new development and reducing long run transmission system costs. Considering these positive impacts is particularly important given the costs of the AMP implementation. Moreover, while the DCG Consortium continues to suggest that DCG Credits or some form of recognition of the positive impacts of DCG are appropriate and the AESO has not properly considered these positive impacts in its planning process, even the information provided by the AESO does not support implementation of the AMP. Comparison to, for instance, the diagrams submitted by the AESO in Proceeding 26090 (e.g., Figure 3, Exhibit 26090-X0084, PDF 8 of 17), suggests that the major "costs" of behind the fence generation to customers were caused by the DCG credits and, without DCG credits, the issue is primarily one of reallocation of costs, as discussed under response 1 above. If billing determinant erosion is a concern and the AESO wants to ensure the DFO loads are paying the transmission tariff as though the DCGs are not connected, the methodology by which DFOs currently calculate DCG Credits may be able to be used for the calculation of DTS charges without requiring ratepayers to pay for new feeder level metering infrastructure. As shown in slide 5 of the AESO's DCG Credit presentation, DFOs that offer DCG Credits currently calculate the hypothetical transmission charges that would have been billed at that substation if the DCG was not connected. These charges could be paid by DFO loads and remitted to the AESO, preventing the need for the AESO to implement costly new procedures and require costly new substation upgrades. In the Meters and Measurement section of the AESO's Q&A Session and Question Board Summary and AESO Replies document, the AESO suggests that this form of calculation in the absence of feeder levels meters would not comply with Measurement Canada guidelines given "issues with non-interval meters, distribution line losses, unaccounted for energy, different meter data managers (MDM), and the need to use deductive totalization against the transformer meter." However, the DCG Consortium would point out that DFOs have been using exactly this methodology in order to determine the total cost of the ISO tariff to be charged to their end-use customers for years. Accordingly, the methodology cannot be prohibited and should be explored as an option. The DCG Consortium suggests however that the simplest, fairest and most reasonable approach is simply to continue with metering and payments as currently structured.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

This response is a joint submission by BluEarth Renewables Inc., Elemental Energy Renewables Inc., and RWE Renewables Canada Holding Inc. (the “DCG Consortium”). This submission represents the consensus view of the group and is submitted on behalf of the group by Power Advisory LLC. While the AESO has indicated that it does not have load data at each DFO feeder, the DCG Consortium’s understanding is that the DFOs do have this data. As part of its participation in previous proceedings, members of the DCG Consortium were able to obtain this data from FortisAlberta in order to do accurate calculations of the impact of both the elimination of DCG Credits and the implementation of the AMP. Had the DCG Consortium chosen to simply assume that there was no load on the same feeder as the generator in order to provide the maximum possible impact of the changes, the DCG Consortium expects parties would have noted as much and taken issue with the analysis in those proceedings. Similarly, the DCG Consortium suggests the AESO should work with the DFOs to obtain the necessary data in order to properly perform this analysis. If nothing else, this data is available in FortisAlberta’s service territory and the AESO has identified FortisAlberta’s service territory as the service territory accounting for the vast majority of the billing determinant erosion (see slide 11 of the "Impact Analysis” slide deck). This feeder level load data is necessary to properly quantify the values on slide 11 of the “Impact Analysis” slide deck which are later used in the cost benefit analysis on slide 8 of the "Moving Forward With the AMP” slide deck. The DCG Consortium notes the AESO’s comment in the Impact Analysis Methodology section of the AESO’s Q&A Session and Question Board Summary and AESO Replies document, where the AESO suggests it was attempting to balance effort and accuracy. The DCG Consortium suggests the AESO should do the analysis properly; however, should the AESO choose to file its application without performing the proper analysis, it must at least be noted and acknowledged that the $16m misallocation result is clearly significantly higher than the actual value that would be achieved through proper analysis as many DCGs are connected to a feeder that also has load and that load was ignored in the analysis. In filing its application, the AESO needs to be abundantly clear about the rate impact shown in the AESO’s Impact of the AMP on Market Participants section of the AESO’s Q&A Session and Question Board Summary and AESO Replies document on PDF pages 17-18. Here the AESO shows a reduction in ISO tariff rates paid by each of the DFOs. On first read, this appeared to suggest that rates would fall for end use customers in each of the DFO service territories by this amount. However, as shown in the AESO’s "Impact Analysis” slide deck on PDF page 11, FortisAlberta customers will pay on aggregate $16m more in tariff costs following implementation of the AMP. This is possible because FortisAlberta, as a DFO, will pay a lower rate on a higher volume of billing determinants. The resulting rates for FortisAlberta’s end-use customers must then also be higher in order for FortisAlberta service territory as a whole to pay $16m/year more. The DCG Consortium suggests that any data showing the rate change to DFOs should focus on the rates to end-use customers and should clearly identify changes to both rates and billing determinants and ultimate overall costs.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

This response is a joint submission by BluEarth Renewables Inc., Elemental Energy Renewables Inc., and RWE Renewables Canada Holding Inc. (the "DCG Consortium"). This submission represents the consensus view of the group and is submitted on behalf of the group by Power Advisory LLC. The AESO's explanations for why it did not want to obtain an AACE Class 3 level cost estimate for each substation are reasonable; however, if that cost estimate is to be directly compared with a quantifiable value for proceeding with the AMP implementation, it is not ideal that the estimates remain in that form. Further, the fact that obtaining these estimates would be more costly than justified demonstrates again that the benefits of implementing the AMP may not outweigh its costs. The DCG Consortium also understands, from AESO Information Document #2015-002R referenced by the AESO, that AACE Class 4 level cost estimates, a level higher than that relied on by the AESO for the AMP implementation, are used for Needs Identification Document estimates which justify significant transmission spending. The lack of detailed cost information is particularly concerning as the AESO has not proposed any tailored methods of cost review and oversight that are appropriate to the implementation of the AMP, instead relying on "the same process as any other transmission facility project." This process does not consider the overall costs of the AMP implementation and does not provide any mechanism to re-examine the implementation of the AMP if costs are higher than projected by the AESO. The cost review mechanisms provided by the AESO do not provide any extra comfort regarding the costs of the AMP implementation than were provided in Proceeding 27047. If the AESO is intent on proceeding in spite of these limitations, given the estimates are accurate to -50% / +100%, a compromise may be that, as well as demonstrating a resolution of the other comments made by the DCG Consortium and other stakeholders, the AESO needs to demonstrate benefits over the estimate +100% (i.e., $60m instead of $30m for short term cost/benefit and $105m instead of $52.5m for long term cost/benefit). If the AESO was able to show sufficiently high benefits associated with the implementation of the AMP, then, the DCG Consortium suggests it may be more reasonable to rely on the lower class cost estimate. However, if the AESO isn't able to show this level of benefits, then the AACE Class 5 estimate and the limited cost review and oversight mechanisms proposed by the AESO may be inadequate. It should also be noted that the costs to obtain the AACE Class 3 estimates and the costs of regulatory proceedings (NIDs and FAs) are also costs that are ultimately borne by ratepayers as the result of a decision to implement the AMP. The AESO should not present artificially low cost estimates to the Commission that consider only the capital costs but no other costs.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

This response is a joint submission by BluEarth Renewables Inc., Elemental Energy Renewables Inc., and RWE Renewables Canada Holding Inc. (the "DCG Consortium"). This submission represents the consensus view of the group and is submitted on behalf of the group by Power Advisory LLC. The DCG Consortium does not support implementing the AMP. However, if the AMP is to be implemented, the DCG Consortium would be opposed to discriminatory legacy treatment for all the same reasons raised in the previous AMP proceeding regarding fairness between DCGs in Alberta. Such discriminatory treatment does not constitute rates that are not unduly preferential, arbitrarily or unjustly discriminatory, and impacts the fair, efficient and openly competitive operation of the electricity market by providing some generators with a competitive advantage over others and changing the factors leading to investment decisions, often after the fact. Discriminatory legacy treatment includes any instance where some DCGs are subject to the AMP before others are, including where substations requiring only administrative changes are subject to the AMP immediately and substations requiring physical changes continue not to be subject to the AMP at least in the short-term.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

This response is a joint submission by BluEarth Renewables Inc., Elemental Energy Renewables Inc., and RWE Renewables Canada Holding Inc. (the “DCG Consortium”). This submission represents the consensus view of the group and is submitted on behalf of the group by Power Advisory LLC. The DCG Consortium does not support implementing the AMP. It should not be implemented unless, in addition to the AESO resolving concerns around justification, discrimination, investor certainty and the fair, efficient and openly competitive operation of the electricity market, the benefit of implementing the AMP outweighs the costs of implementing the AMP. As explained in the above responses, this means the AESO must show at least $105m in benefits (hopefully mostly or completely in the form of true cost savings to aggregate customers) in order to justify the implementation of the AMP. The DCG Consortium also suggests that such calculation of benefits should properly take into consideration the possible benefits of behind the fence generation as discussed above. Regarding objectives, the DCG Consortium suggests that investor certainty and the principle of non-discrimination should be primary objectives of any and all changes the AESO looks to make to rules or tariffs in Alberta, considering principles of economic regulation and the fair, efficient and openly competitive operation of the Alberta electricity market. In addition to these general principles, the DCG Consortium strongly supports the AESO’s first and third principles regarding cost treatment listed on PDF page 26 of the AESO’s Q&A Session and Question Board Summary and AESO Replies document, in the Upcoming AUC Application section.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.**

DCG Consortium AMP Consultation Comments

Respondent No: 7
Login: CapitalPower
Email: mgill@capitalpower.com

Responded At: Apr 21, 2023 12:27:00 pm

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

Capital Power has no major concerns regarding the AESO's proposed implementation of the AMP. With respect to the proposed totalization of billing within a substation, Capital Power is very supportive of this change. We agree that not allowing the totalization of multiple points of supply within a substation would create an artificial barrier that limits market participants to aggregate some or all of its generating units. Furthermore, allowing the totalization of multiple points of supply is more administratively efficient. It is our view that the AESO should proceed with an application for the proposed revision to the ISO tariff to include the Totalized Billing within a Substation provision regardless of how it decides to proceed with the AMP application.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

In principle, Capital Power agrees that the issue should be addressed to improve billing and metering accuracy and avoid artificially "eroding" the pool of billing determinants if the benefits of doing so exceed the costs.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

Capital Power has no comment at this time.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

Capital Power has no comment at this time.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

Capital Power has no comment at this time.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

Capital Power has no comment at this time.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.**

not answered

Respondent No: 8
Login: ATCO-Nathan-Coutu
Email: nathan.coutu@atco.com
Responded At: Apr 21, 2023 13:02:58 pm

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

ATCO believes AMP is a tool-in-the-toolbox that can be used (implemented only at substations where the benefits outstrip the infrastructure costs). However, other solutions should be prioritized, such as rate redesign (ensuring that sunk costs get recovered and utilization is encouraged) and evaluating net metering/billing practices. ATCO believes AMP does not entirely address issues described in Bill 22, which allows for transmission rates to self-suppliers and exporters.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

ATCO agrees that the determinant billing erosion and uneconomical bypass must be addressed, as this puts upward pressure on rates and cost-shifting from participating customers to non-participating customers. Tools identified in question 1 can be used to reduce this bypass and erosion of billing determinants. Billing determinant erosion has steadily increased and will continue to increase as more DCG connects.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

3. The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

ATCO does not have a comment since this does not apply to our organization.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

If AMP is implemented, ATCO supports implementing it without legacy treatment. The administrative changes needed to configure measurement data systems and system access service agreements should be universally applied to all substations with reversing flows. If there were to be a dual measurement practice with AMP and a legacy treatment without AMP, tracking which PODs are subject to which practice would become a burdensome administrative effort. ATCO is also a Market Participant with customers with behind-the-fence generation connections that impact the net energy flows to the transmission system and a legacy treatment would become increasingly complex to administer contract changes with the addition of new generation customers or any changes to existing generators.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

ATCO Electric supports implementing the AMP in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates, thereby minimizing the cost impact on our customers.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.** not answered

Respondent No: 9
Login: VEL-Codd
Email: chris@versoriumenergy.com

Responded At: Apr 21, 2023 14:16:18 pm

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

No, we do not support approval and implementation of the AMP. We share the concern of other stakeholders that the AMP as currently proposed is adding costs without creating any benefits, and the identified benefits are only a redistribution of costs. We are also concerned that the AMP proposal will become a major obstacle to DFO-implemented NWAs. The AESO's assessment of benefits and costs is too limited to address the Commission's concerns in Decision 27047-D01-2022 because it only consider the direct costs and redistributions created by implementing the AMP and ignores the second order impacts caused by the AMP proposal. We also view the AMP proposal as raising cost causation issues because it will charge DFOs bulk and regional system costs for intra-substation flows that never reach the deeper system and do not drive bulk or regional system costs. The AESO has stated that there have been no substation upgrades caused by intra-substation flows but the AMP proposal would charge DFOs bulk and regional rates for such flows.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

No, we do not agree that the "billing determinant erosion" needs to be addressed. The AESO has not identified any transmission costs caused by intra-substation flows and therefore there are no costs associated with the billing determinant erosion that the AMP is intended to address. The intra-substation flows identified as billing determinant erosion are an efficient use of the transmission system because they facilitate load being served locally by DERs without driving additional transmission costs. Addressing "billing determinant erosion" would increase transmission costs to the customers efficiently using the transmission system by transferring costs from other customers that use the transmission system less efficiently.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

We recommend that the AESO assess the second order impacts of the AMP proposal, as described earlier. The second order impacts of the AMP would include: - disincentivizing efficient use of the transmission system and the corresponding increase transmission costs caused by creating or advancing needs as well as deterring lower cost solutions such as non-wires alternatives; - skewing transmission planning processes that rely on STS and DTS contract capacities; and - unintended incentives created by authoritative and information documents that rely on Rate DTS and STS contract capacities. For example, as currently proposed the DER anti-islanding requirements rely on DER-specific STS values regardless of whether the actual energy from the DER net of load has the potential to form localized generation/load island. This inefficient and arbitrary approach imposes significant costs on generation developers.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

No comment

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

No comment

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

No comment

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.**

not answered

Respondent No: 10 **Responded At:** Apr 21, 2023 15:10:28 pm
Login: AltaLink - Lee Ann Kerr
Email: leeann.kerr@altalink.ca

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

AML supports the AESO's attempts to address the erosion of load billing determinants that is occurring at the DFO substations. However, the AMP currently being proposed by the AESO only partially and insufficiently addresses the current and growing billing determinant erosion problem. AML submits that the AESO should investigate an alternative solution which can be described as administrative or as an adjusted billing practice. This alternative would capture a great deal more DCG-related billing determinant erosion than the AMP proposal, perhaps sufficiently so, and would eliminate the need to install new feeder-level meters, thus avoiding the associated capital cost. The AESO has itself recognized in the past that the AMP will only partially address DCG-related billing determinant erosion, and this results in harm to load customers. For example, in paragraph 620 of AUC Decision 22942-D02-2019 , the AUC included the AESO's recognition of the AMP's limitation: […] (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. … (emphasis added)

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

AML agrees that load billing determinant erosion caused by DCG is currently occurring and needs to be addressed. If not sufficiently addressed, all else equal, load customers directly connected to the transmission system and DFOs with low DCG penetration will pay more for transmission service than DFOs with high DCG penetration, all of whom receive similar transmission service. Further, all else equal, because DFOs recover transmission costs from their distribution-connected load customers, distribution-connected load customers located in a DFO service territory with high DCG penetration will pay more for transmission service than distribution-connected load customers located a DFO service territory with low DCG penetration. In paragraph 23 of AUC Decision 26090-D01-2021 , the AUC succinctly described the problem of DCG-related billing determinant erosion which recognizes the negative impact that all DCG output has on billing determinants: "If DCG is able to locate on a distribution feeder that also serves load and is able to generate electricity coincident with that load, its operation reduces the flow of energy from the transmission system to the substation. Given the current AESO tariff design and metering locations, these reduced flows serve to lower the transmission billing determinants of metered demand and energy at the substation. Since a considerable portion of the AESO's tariff is collected from its bulk and regional charges on the basis of the monthly coincident peak of the system (12 CP), the reduction in metered demand coincident to the peak can significantly reduce the bill received by the distribution utility from the AESO for transmission service due to the presence of DCG on the feeder." It seems the AUC recognized the full extent of the problem and would possibly support a remedy that is blind to whether the impact of DCG occurs above or below the feeder level. It is well-documented that distribution-connected load customers receive similar transmission services as load customers who are directly connected to the transmission system. These services include but are not limited to: reliability; load following and equipment start-up power; frequency and voltage support; and, most importantly, access to contracted, wholesale and retail energy transactions. Pages 16-20 of the EPRI report , which was submitted during the AESO 2018 ISO Tariff proceeding and the AUC's Distribution System Inquiry , discusses these benefits in more detail. For distribution-connected load customers to potentially pay less for the same transmission service, simply as a result of something like high levels of DCG, is unfair and represents a form of cross-subsidization. In the "Adjusted Metering Practice - Q&A Session and Question Board Summary and AESO Replies" AML notes the responses to AML's questions labeled # 10, 11 on page 4, paragraph 3, where the AESO states: "More specifically, the AMP is not meant to address the billing determinant erosion due to a reduction of flows because load is being served by DCG on the same feeder. The AESO only provides system access service at a point of connection to the transmission system and does not provide service downstream of a point of connection to the transmission system…" AML respectfully disagrees with this response. First, DCG does not serve the load on the feeder or provide the grid services mentioned in the EPRI report that are provided by the transmission system. Second, the transmission system does provide services downstream of the point of connection; this is the very nature of the benefits of a networked system which can only be provided by the transmission system. In the absence of DCG or behind-the-meter generation generally, metered flows (i.e., capacity (MW) and energy (MWh)) can act as a reasonable proxy for assessing the use of the transmission system by load. However, if the billing determinants do not accurately reflect the total potential load that uses the transmission system, then using flows as a billing determinant will be flawed; and further, any tariff design that uses these determinants (i.e., flows) will also be flawed.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

AML has a concern with the AESO's impact analysis. AML considers that all DCG can cause an erosion of the DFO load billing determinants and therefore all DCG should be accounted for when completing any analysis. The AESO's analysis, as currently presented, only accounts for netting of load and DCG flows occurring at the feeders if it registers a negative flow at the substation (i.e., flow into the substation from a DFO feeder). This analysis does not account for the netting of load and DCG flows occurring downstream of the feeders where DCG nets with the load before entering the substation. AML considers the level of billing determinant erosion occurring is substantially higher than the AESO has estimated. As an example of the billing determinant erosion not currently being accounted for by the AESO, below is a before (Figure 1 a, b, c) and after (Figure 2 a, b, c) scenario highlighting this situation. Figure 1a demonstrates a Base Case Scenario where the DTS billing determinants for a DFO substation is only serving load; Figure 1b shows the Base Case Load Profile; and Figure 1c shows the Base Case Billing Information for this substation. Figure 2a is the same substation but with a DCG added at some future date on a distribution feeder just outside the substation, with Figure 2b showing the impact this added DCG will have on the load profile and Figure 2c showing the impact to the substation billing information. Graphs and schematics included in "formatted" document uploaded. When comparing the two scenarios above, it is apparent that the addition of DCG can have a significant impact on the billing determinants and resulting bills to be paid by a DFO. The analysis shows that approximately $ 1.6 million/year or a 21% loss of revenue will occur when a DCG of this type is added at this substation. This foregone revenue must then be recovered from all transmission-connected load customers including other DFOs with lower levels of DCG (the other DFOs will recover their portion of this foregone revenue from distribution-connected load customers who reside in their service territories). AML suggests the AESO analyze the impact that DCG has on each individual DFO substation's billing determinants and calculate the foregone revenue occurring at each site. This analysis should be relatively straightforward to complete as the AESO has totalized interval metered data at all DFO substations and has indicated that it has individual interval metered data for a substantial amount of the DCG. This analysis, complete with any associated spreadsheets, should then be provided to stakeholders as part of the consultation process. In lieu of a broader detailed analysis, AML performed the following high-level estimate of province-wide billing determinant erosion and the associated revenue impact: The AESO indicates in slide 7 of its "Background and Ongoing Need" deck that installed DCG capacity was approximately 650 MW in 2018; and in slide 15 of the same deck, current installed DCG capacity is 1,438 MW. As shown in Table 1 of AUC Decision 26090-D01-2021 , DFOs paid $28.2 million to DCGs in 2018. If we assume the DCG credits paid by the DFOs to DCGs were reflective of the billing determinant erosion occurring and then adjust the 2018 amount paid by DFOs to DCGs to 2022 (i.e., 1,438 MW/650MW), the current foregone revenue due to DCG billing determinants erosion is approximately $60 million. For comparison purposes, slide 11 of the AESO's "Impact Analysis" deck shows that the AESO's AMP proposal only captures approximately $16 million worth of the billing determinant erosion that is currently occurring. This represents a significant difference in foregone AESO tariff revenue, and AML suggests that its estimate of $60 million could be conservative. As an alternative to the current AMP approach proposed by the AESO, AML proposes a Billing Adjustment approach to correct the DCG-related billing determinant erosion in more appropriate and complete manner than AMP without incurring the additional cost of installing meters. Under the proposed Billing Adjustment approach, the AESO would sum the interval metered data for each DCG connected to a particular substation which will then provide an accurate assessment of the level of erosion that has occurred to the substation load billing determinants. Adding the summed DCG data back to the substation totalized metered data will provide correct load billing determinant adjustments and allow the AESO to collect otherwise forgone tariff revenue resulting from DCG-related billing determinant erosion. The following is an illustrative example of the Billing Adjustment approach discussed above. (See Figure 2 Base Case Plus DCG Scenario above for reference) Corrected Substation metering = M1 + M6 = 25MW + 10 MW = 35 MW = substation metering prior to the addition of DCG

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

AML has proposed an alternative solution to the AESO's AMP proposal which does not require the installation of new feeder-level meters. Therefore, AML has no comment with respect to the AESO's cost estimates for AMP. As AML has discussed above, a more accurate assessment of billing determinant erosion should be completed, and AML considers this type of analysis could be translated into an administrative model that can be used for determining accurate billing determinants in real time for each individual substation. With the AESO having the appropriate metering point data available to it, the costs to implement should be minimal as it is anticipated that only administrative procedures and perhaps billing engine upgrades would be required. With respect to the feasibility of implementing AML's proposed alternative to AMP, AML notes the AESO's following assertion made in a response included in the "Adjusted Metering Practice - Q&A Session and Question Board Summary and AESO Replies": "The installation of meters at the feeder connection in a substation is the only option for implementing the AMP (subject to legacy treatment considerations). The individual energy flows into and out of a substation on each feeder are required to produce the necessary measurement data and cannot be accurately extrapolated using other metered data available to settlement, due to issues with non-interval meters, distribution line losses, unaccounted for energy, different meter data managers (MDM), and the need to use deductive totalization against the transformer meter (a practice prohibited by Measurement Canada)." AML respectfully disagrees with this assertion as it considers an administrative solution exists to address billing determinant erosion. The DFOs, for example, have long been able to administratively calculate DCG credits by combining the necessary measurement data available from the substation and the DCG metering points to determine the billing determinants required to calculate a DCG credit. AML considers a similar process (in reverse) could be used to implement its proposed alternative. AML submits the AESO should not proceed with its proposed AMP until an alternative administrative solution is thoroughly investigated and results shared with stakeholders.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

AML does not support legacy treatment of incorrect load billing determinants for DFO substations as the typical bill impact on load customers served from a distribution system will likely be below 10%. If, however, the AESO indicates the typical bill impact is potentially greater than 10%, then the AESO should perform and share a typical bill analysis as part of the stakeholder process.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

As should be evident by its proposed alternative to AMP, AML supports implementing a means for resolving billing determinant erosion that emphasizes minimization of implementation costs that would be recovered through ISO tariff rates, especially when the proposed alternative to AMP more thoroughly resolves the problem of billing determinant erosion.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.**

AML Feedback on AMP

Respondent No: 11 **Responded At:** Apr 21, 2023 15:23:22 pm

Login: EPCOR-Regulatory-Affairs

Email: regulatoryaffairs@epcor.com

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

EDTI agrees that the current metering practice does not align with the Electric Utilities Act definition of "Transmission Facility" and that the current practice does not properly allocate SAS costs to all users of the transmission system. In principle, EDTI supports the correction of this misalignment and recognizes that the AMP would do so. EDTI notes that potential future changes to legislation (including the Transmission Regulation) may impact the drivers of the Adjusted Metering Practice.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

See response to #1.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

EDTI does not have any comments or suggested improvements on the illustrative analysis at this time.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

EDTI does not have any comments or suggested improvements on the maximum cost calculations at this time.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

EDTI understands that AMP "with legacy treatment" would not address the existing billing determinant erosion and so is an imperfect solution, however it would avoid the potentially costly retrofitting of existing non-compliant substations (noting the theoretical maximum cost of $52 million calculated by the AESO). Consistent with response to #6, EDTI would support the implementation of AMP with legacy treatment as a cost minimization measure. However, EDTI is concerned that the proposed treatment of future metering costs as "Participant" will create a number of fairness issues, and would create a costly barrier to entry for future DCGs if the need for AMP metering is triggered by a proposed project. The proposed cost treatment would also create a location signal for DCGs as it would unfairly penalize AMP-triggering DCGs connecting within the service territory of a TFO that for whatever reason had not previously installed feeder metering. EDTI suggests that the classification of the costs of installing AMP metering at any existing substation, regardless of whether the need for metering is triggered by existing DCG or future DCG, should be consistent and that in both cases the costs should be classified as "System" costs.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

EDTI considers that cost minimization is an important principle and supports the implementation of AMP in a way that minimizes additional costs to ratepayers. However, the specific goal of minimizing costs to be recovered through the ISO tariff (versus the broader goal of minimizing ratepayer costs in general) may result in fairness issues as noted in EDTI's response to #5 above. EDTI submits that the AMP should be implemented in a manner that considers the costs to be borne by all parties regardless of recovery mechanism.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.**

not answered

Respondent No: 12 **Responded At:** Apr 21, 2023 16:31:32 pm
Login: Lionstooth-ErikaGoddard
Email: erika.goddard@lionstoothenergy.com

Q1. **Do you support approval and implementation of the AMP? Why or why not?**

Lionstooth does not support the AMP, and does not support a future application to the Commission to “confirm the AUC’s approval of the AMP, and if that confirmation is provided, to obtain confirmation from the AUC of whether or not the AMP should be implemented with or without legacy treatment” (AESO Q&A Summary & Reply, pdf pg 22). In Decision 27047, the Commission concluded that the AESO is “not required by the Commission to file a further application proposing an implementation plan for the AMP” (paragraph 23). This is clear direction from the Commission. The fact that the AESO took issue with one of the reasons the Commission denied Application 27047, does not negate the fact that there was not “sufficient information for the Commission to determine if approval of the application was in the public interest or supported the fair, efficient, and openly competitive operation of the electricity market” (Decision 27047, paragraph 2). The Commission provided the AESO with clear direction if another AMP application was to be filed. This included Class 3 costs estimates, or mechanisms for cost review and oversight, Class 5 cost estimates of the total theoretical maximum cost, and quantification of the benefits of the AMP, including a cost-benefit analysis (Decision 27047, paragraph 23). While the AESO has produced more materials related to the AMP, these additional materials have raised more uncertainty and potential for unintended consequences (i.e. impacts to loss factors), and do not comply with the very clear direction from the Commission in Decision 27047. Even though “parties had previously expressed to the AESO the desire to minimize time and effort required for the AMP without a clear and final decision from the AUC” (AESO Q&A Summary & Reply, pdf pg 13), to return to the Commission without following their direction, will continue to result in insufficient information to assess if the AMP is in the public interest or supportive of a FEOC EOM. Further, it is our understanding that the AESO has estimated savings per customer to be just over $1/MWh. Lionstooth questions why the AESO, market participants, and customers (load and generation) are expending time, effort, and resources for such a small benefit, when much more significant benefits could be achieved by improving system planning, optimizing the use of the entire existing Integrated Electric System, and reducing the overall revenue requirement. The AESO’s assertion that the AMP is “not related to transmission system planning” (AESO Q&A Summary & Reply, pdf pg 10) highlights a key misunderstanding in how AESO signals influence generator siting decisions, and how generator siting decisions influence system planning. The AMP, as outlined today, would send a strong dis-incentive to locate DCG in urban areas, near load, and where if right-sized, could defer or avoid the need for new incremental wires. The AMP does nothing for the affordability of delivered electricity for Albertans, and therefore should no longer be an active engagement or priority for the AESO.

Q2. **Do you agree that the issue of billing determinant erosion due to the AESO’s current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

Lionstooth does not agree that the “artificial” billing determinant erosion due to the current measurement practice needs to be addressed. The AESO has suggested that the “artificial” billing determinant erosion will continue to increase. This is misleading. First, the AESO has relied on their Connection Project List as an indication of near-term DCG growth, without taking into consideration forthcoming changes as a result of the Connection Process Streamlining initiative, which is anticipated to reduce the number of projects in the Connection Project List. Second, the AESO has not accounted for growth on the Dx system as part of the electrification of society, which does include near-term (1-3 years out) response from customers on the Dx system. Again, while the AESO produced additional materials related to the AMP, these materials have raised more uncertainty and potential for unintended consequences, have failed to meet the direction of the Commission, and has demonstrated that the AMP does not improve the affordability of delivered electricity. For these reasons alone, the AMP initiative should be dropped. The primary issue that the AESO needs to address is the overbuilt transmission system, and improvements to planning that need to be implemented immediately to correct this.

Q3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

Per Decision 27047, the AESO was directed by the Commission to include quantification of the benefits of the AMP, including a cost-benefit analysis, in any subsequent re-applications, and the AESO Q&A Summary & Reply demonstrates why complete impact analysis is so important. The additional materials produced by the AESO in this engagement have raised more uncertainty and potential for unintended consequences as a result of AMP. This includes: potential impacts to Loss Factors (which have yet to be fully explored), and the re-allocation of costs between DFOs / MPs (that clearly negatively impacts one group of ratepayers, who already have paid for feeder-level metering via rate base, and consequently may be doubly impacted by the AMP). There also remain troubling disparities between different customer groups as a result of the AMP. This includes: urban versus rural DFO customers, urban versus rural DCG, and existing versus future DCG. Having said all this, and appreciating that the AESO has requested feedback on how to address impact analysis challenges, based on the savings estimated in Section 3, and the additional simplified savings per customer calculated in the AESO Q&A Summary & Reply, of just over $1/MWh, Lionstooth does not support expending any further resources to refine the AESO's impact analysis. The impact analysis completed to date has confirmed that there are limited improvements in the affordability of delivered electricity for Albertans as a result of the AMP, and so AESO time, effort, and resources should shift to where much more significant benefits could be achieved by improving system planning, optimizing the use of the entire existing Integrated Electric System, and reducing the overall revenue requirement.

Q4. **The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.**

In our experience, developing DCG in Alberta, initial utility cost estimates are consistently under-estimating final costs, and often close to or over the +100% upper bound of a Class 5 estimate. The AESO should have engaged an urban TFO outside of the Connection Process, or any one of the many independent engineering firms that the utilities subcontract to, in order to obtain a Class 3 estimate. The AESO intends to spend over $5 million on consultants in 2023 (per the 2023 BRP), and to conduct this exercise at 2 substations ($150K) represents about a 2% increase to that individual budget line item. In consultation with the DFO and TFO, the AESO should have identified two "book-end" substations (1 deep urban and complex, and one suburban and simple). By not completing this analysis, as directed by the Commission, there continues to be insufficient information to assess if the AMP is in the public interest or supportive of a FEOC EOM.

Q5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

Lionstooth does not support the AMP, and it is unnecessary to discuss legacy treatment or implementation of the AMP, given the very clear direction provided by the Commission in Decision 27047, and the limited improvements in affordability of delivered electricity for Albertans as a result of the AMP. Even if the AESO dismisses Lionstooth's objections, and proceeds with an application to confirm if the AUC would even approve the AMP, to discuss legacy treatment or implementation in advance of a ruling on this initial issue, could imply that there is full support for proceeding with the AMP, potentially introducing bias.

Q6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?**

Lionstooth does not support the AMP. The 12 additional considerations / trade-offs the AESO has included in the AESO Q&A Summary & Reply further demonstrate the large holes in the AMP. These are not issues that should be resolved in front of the Commission, rather issues that should be addressed prior to support an efficient and effective process. Further, there remains a material issue with who pays for the AMP implementation, both in terms of parity, locational signals, and impacts to customers. While the AESO has again deferred flowthrough of costs to the DFO, and has stated “the AESO will not be determining what portion of the metering retrofits should be paid by a DCG vs other DFO customer” (AESO Q&A Summary & Reply, pdf pg 25), the existing feeder level metering installed in the province was done so as a system cost. In Decision 26911, the Commission provided notice that “the Commission intends to consider bill impacts to customers of the electric distribution utilities” (paragraph 151). It is not appropriate to ignore cost impacts to end-use customers, simply because they are served on the Dx system. The AESO’s additional materials produced in this engagement raised more uncertainty and potential for unintended consequences, have failed to meet the direction of the Commission, and has demonstrated that the AMP does not improve the affordability of delivered electricity.

Q7. **If you would like to upload a formatted version of your survey responses, please do so here.**

not answered

This response is a joint submission by BluEarth Renewables Inc., Elemental Energy Renewables Inc., and RWE Renewables Canada Holding Inc. (the "DCG Consortium"). This submission represents the consensus view of the group and is submitted on behalf of the group by Power Advisory LLC.

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1. Do you support approval and implementation of the AMP? Why or why not?

The DCG Consortium does not support approval and implementation of the AMP.

The AMP is unnecessary to address the issue of billing determinant erosion (see response to question 2).

Further, the AESO's "cost benefit analysis" does not identify any real costs to aggregate ratepayers of the ISO tariff of not proceeding with the AMP and does not quantify the dollar value of benefits associated with reducing or eliminating the identified misallocation.

The DCG Consortium supports the AESO's recharacterization of this work as a "cost impact analysis" as it measures the value of misallocation. As acknowledged by the AESO in recent consultation, the $16m/year in annual misallocation identified on the slide titled "The Total Costs and Benefits of Implementing the AMP", in the "Moving Forward With the AMP" slide deck, is not a "cost" to net transmission customers (and accordingly, preventing $16m/year in misallocation does not result in a $16m/year "benefit"). Rather, it quantifies the amount of money that would be shifted annually from one set of ratepayers to another. While cross subsidization and inefficiently high tariff rates can cause a cost to customers, the AESO has not highlighted or attempted to quantify any such costs.

The "misallocated" $16m/year would be collected from different customers with the AMP than without it, but on net, the total cost to transmission customers would be the same. Meanwhile, the $30m - $52.5m cost of implementing AMP is a real cost that will increase the total annual transmission revenue requirement to be collected from customers.

The AESO should be approaching this, and all other major transmission policy matters, with consideration for affordability (including the potential for negative investor certainty impacts that ultimately increase customer costs) and impacts on the fair, efficient and openly competitive operation of the electricity market. Accordingly, amongst other considerations, if the AESO cannot identify a real cost to ratepayers of not implementing the AMP that is greater than at least $30m, if not $52.5m or $105m (as discussed below), then the AESO should not proceed with its application for the AMP implementation. It particularly should not do so in a form that preferences some generators over others and is thus discriminatory.

The DCG Consortium also suggests that the time and effort that would be invested in AMP approval and implementation (including the regulatory proceeding and other implementation efforts) could be better spent on higher priority issues such as advancing an energy storage tariff module which was recently identified as a priority issue by stakeholders at the Tariff Evolution Roundtable & Work Café held on February 14, 2023, or other key issues such as system vs participant costs, which is an issue currently creating an unlevel playing field between generators.

Lastly, the DCG Consortium suggests it may be more prudent to proceed with the AMP after the resolution of the bulk and regional tariff design. The next ISO tariff application may include rates that are almost fully fixed (in response to Decision 26911-D01-2022). Accordingly, the benefit of implementing the AMP will fall significantly. Any ISO tariff that bills based on either a fixed monthly per site fee or an NCP charge that includes a 12-month ratchet rate, such as the current NCP rate design, will not result in billing determinant erosion due to any DCG that needs to go down for either planned or unplanned maintenance at least once a year or due to any DCG with a variable fuel source that isn't operating at maximum capacity in all hours. Given that the next tariff design could render the AMP unnecessary, it is imprudent for the AESO to spend as much as $105m in ratepayer money to address its outlined concerns. The AESO should instead wait until its next ISO tariff is approved and then re-assess at that time if it continues to consider there to be measurable benefits from the AMP. If so, it should re-start this consultation at that time with an updated cost-impact analysis. The AESO's assertion that "the measurement practice should not unnecessarily constrain the rate design" is not sufficient justification for the capital outlays and other negative impacts of AMP implementation. Any necessary changes to the measurement practice can follow any approved changes in rate design to the extent they are required.

2. Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?

A minuscule amount of the total transmission revenue requirement is attributable to the cost of feeders on substations. The AESO is looking to add into the accounting of billing determinants, for the purposes of charging out the total transmission revenue requirement, the power that flows across only feeders without making use of any other transmission infrastructure. The additional MWs are not contributing to the cost of or benefiting from the existence of the vast majority of transmission infrastructure.

Given that the AESO is only proposing to apply the AMP to DFO substations, then the issue highlighted by the AESO in this question is no different from the impact of any other behind the fence generation and is arguably positive for the transmission system. Load is receiving power with less reliance on the transmission system, freeing up transmission capacity for new development and reducing long run transmission system costs. Considering these positive impacts is particularly important given the costs of the AMP implementation. Moreover, while the DCG Consortium continues to suggest that DCG Credits or some form of recognition of the positive impacts of DCG are appropriate and the AESO has not properly considered these positive impacts in its planning process, even the information provided by the AESO does not support implementation of the AMP. Comparison to, for instance, the diagrams submitted by the AESO in Proceeding 26090 (*e.g.,* Figure 3, Exhibit 26090-X0084, PDF 8 of 17), suggests that the major "costs" of behind the fence generation to customers were caused by the DCG credits and, without DCG credits, the issue is primarily one of reallocation of costs, as discussed under response 1 above.

If billing determinant erosion is a concern and the AESO wants to ensure the DFO loads are paying the transmission tariff as though the DCGs are not connected, the methodology by which DFOs currently calculate DCG Credits may be able to be used for the calculation of DTS charges without requiring ratepayers to pay for new feeder level metering infrastructure. As shown in slide 5 of the AESO's DCG Credit presentation, DFOs that offer DCG Credits currently calculate the hypothetical transmission charges that would have been billed at that substation if the DCG was not connected. These charges could be paid by DFO loads and remitted to the AESO, preventing the need for the AESO to implement costly new procedures and require costly new substation upgrades. In the Meters and Measurement section of the AESO's Q&A Session and Question Board Summary and AESO Replies document, the AESO suggests that this form of calculation in the absence of feeder levels meters would not comply with Measurement Canada guidelines given "issues with non-interval meters, distribution line losses, unaccounted for energy, different meter data managers (MDM), and the need to use deductive totalization against the transformer meter." However, the DCG Consortium would point out that DFOs have been using exactly this methodology in order to determine the total cost of the ISO tariff to be charged to their end-use customers for years. Accordingly, the methodology cannot be prohibited and should be explored as an option.

The DCG Consortium suggests however that the simplest, fairest and most reasonable approach is simply to continue with metering and payments as currently structured.

3. The AESO has described the challenges in creating an accurate impact analysis in Section 3. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.

While the AESO has indicated that it does not have load data at each DFO feeder, the DCG Consortium's understanding is that the DFOs do have this data. As part of its participation in previous proceedings, members of the DCG Consortium were able to obtain this data from FortisAlberta in order to do accurate calculations of the impact of both the elimination of DCG Credits and the implementation of the AMP. Had the DCG Consortium chosen to simply assume that there was no load on the same feeder as the generator in order to provide the maximum possible impact of the changes, the DCG Consortium expects parties would have noted as much and taken issue with the analysis in those proceedings.

Similarly, the DCG Consortium suggests the AESO should work with the DFOs to obtain the necessary data in order to properly perform this analysis. If nothing else, this data is available in FortisAlberta's service territory and the AESO has identified FortisAlberta's service territory as the service territory accounting for the vast majority of the billing determinant erosion (see slide 11 of the "Impact Analysis" slide deck). This feeder level load data is necessary to properly quantify the values on slide 11 of the "Impact Analysis" slide deck which are later used in the cost benefit analysis on slide 8 of the "Moving Forward With the AMP" slide deck.

The DCG Consortium notes the AESO's comment in the Impact Analysis Methodology section of the AESO's Q&A Session and Question Board Summary and AESO Replies document, where the AESO suggests it was attempting to balance effort and accuracy. The DCG Consortium suggests the AESO should do the analysis properly; however, should the AESO choose to file its application without performing the proper analysis, it must at least be noted and acknowledged that the $16m misallocation result is clearly significantly higher than the actual value that would be achieved through proper analysis as many DCGs are connected to a feeder that also has load and that load was ignored in the analysis.

In filing its application, the AESO needs to be abundantly clear about the rate impact shown in the AESO's Impact of the AMP on Market Participants section of the AESO's Q&A Session and Question Board Summary and AESO Replies document on PDF pages 17-18. Here the AESO shows a reduction in ISO tariff rates paid by each of the DFOs. On first read, this appeared to suggest that rates would fall for end use customers in each of the DFO service territories by this amount. However, as shown in the AESO's "Impact Analysis" slide deck on PDF page 11, FortisAlberta customers will pay on aggregate $16m more in tariff costs following implementation of the AMP. This is possible because FortisAlberta, as a DFO, will pay a lower rate on a higher volume of billing determinants. The resulting rates for FortisAlberta's end-use customers must then also be higher in order for FortisAlberta service territory as a whole to pay $16m/year more. The DCG Consortium suggests that any data showing the rate change to DFOs should focus on the rates to end-use customers and should clearly identify changes to both rates and billing determinants and ultimate overall costs.

4. The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.

The AESO's explanations for why it did not want to obtain an AACE Class 3 level cost estimate for each substation are reasonable; however, if that cost estimate is to be directly compared with a quantifiable value for proceeding with the AMP implementation, it is not ideal that the estimates remain in that form. Further, the fact that obtaining these estimates would be more costly than justified demonstrates again that the benefits of implementing the AMP may not outweigh its costs. The DCG Consortium also understands, from AESO Information Document #2015-002R referenced by the AESO, that AACE Class 4 level cost estimates, a level higher than that relied on by the AESO for the AMP implementation, are used for Needs Identification Document estimates which justify significant transmission spending.

The lack of detailed cost information is particularly concerning as the AESO has not proposed any tailored methods of cost review and oversight that are appropriate to the implementation of the AMP, instead relying on "the same process as any other transmission facility project." This process does not consider the overall costs of the AMP implementation and does not provide any mechanism to re-examine the implementation of the AMP if costs are higher than projected by the AESO. The cost review mechanisms provided by the AESO do not provide any extra comfort regarding the costs of the AMP implementation than were provided in Proceeding 27047.

If the AESO is intent on proceeding in spite of these limitations, given the estimates are accurate to -50% / +100%, a compromise may be that, as well as demonstrating a resolution of the other comments made by the DCG Consortium and other stakeholders, the AESO needs to demonstrate benefits over the estimate +100% (*i.e.*, $60m instead of $30m for short term cost/benefit and $105m instead of $52.5m for long term cost/benefit). If the AESO was able to show sufficiently high benefits associated with the implementation of the AMP, then, the DCG Consortium suggests it may be more reasonable to rely on the lower class cost estimate. However, if the AESO isn't able to show this level of benefits, then the AACE Class 5 estimate and the limited cost review and oversight mechanisms proposed by the AESO may be inadequate.

It should also be noted that the costs to obtain the AACE Class 3 estimates and the costs of regulatory proceedings (NIDs and FAs) are also costs that are ultimately borne by ratepayers as the result of a decision to implement the AMP. The AESO should not present artificially low cost estimates to the Commission that consider only the capital costs but no other costs.

5. If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.

The DCG Consortium does not support implementing the AMP. However, if the AMP is to be implemented, the DCG Consortium would be opposed to discriminatory legacy treatment for all the same reasons raised in the previous AMP proceeding regarding fairness between DCGs in Alberta. Such discriminatory treatment does not constitute rates that are not unduly preferential, arbitrarily or unjustly discriminatory, and impacts the fair, efficient and openly competitive operation of the electricity market by providing some generators with a competitive advantage over others and changing the factors leading to investment decisions, often after the fact. Discriminatory legacy treatment includes any instance where some DCGs are subject to the AMP before others are, including where substations requiring only administrative changes are subject to the AMP immediately and substations requiring physical changes continue not to be subject to the AMP at least in the short-term.

6. If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates? Why or why not? Are there other considerations or objectives that should be taken into account or prioritized by the AESO?

The DCG Consortium does not support implementing the AMP. It should not be implemented unless, in addition to the AESO resolving concerns around justification, discrimination, investor certainty and the fair, efficient and openly competitive operation of the electricity market, the benefit of implementing the AMP outweighs the costs of implementing the AMP. As explained in the above responses, this means the AESO must show at least $105m in benefits (hopefully mostly or completely in the form of true cost savings to aggregate customers) in order to justify the implementation of the AMP. The DCG Consortium also suggests that such calculation of benefits should properly take into consideration the possible benefits of behind the fence generation as discussed above.

Regarding objectives, the DCG Consortium suggests that investor certainty and the principle of non-discrimination should be primary objectives of any and all changes the AESO looks to make to rules or tariffs in Alberta, considering principles of economic regulation and the fair, efficient and openly competitive operation of the Alberta electricity market.

In addition to these general principles, the DCG Consortium strongly supports the AESO's first and third principles regarding cost treatment listed on PDF page 26 of the AESO's Q&A Session and Question Board Summary and AESO Replies document, in the Upcoming AUC Application section.

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April 21, 2023

AESO Stakeholder Feedback Questions – Adjusted Metering Practice (AMP)

AML Responses:

1. **Do you support approval and implementation of the AMP? Why or why not?**

   AML supports the AESO's attempts to address the erosion of load billing determinants that is occurring at the DFO substations. However, the AMP currently being proposed by the AESO only partially and insufficiently addresses the current and growing billing determinant erosion problem. AML submits that the AESO should investigate an alternative solution which can be described as administrative or as an adjusted <u>billing</u> practice. This alternative would capture a great deal more DCG-related billing determinant erosion than the AMP proposal, perhaps sufficiently so, and would eliminate the need to install new feeder-level meters, thus avoiding the associated capital cost.

   The AESO has itself recognized in the past that the AMP will only partially address DCG-related billing determinant erosion, and this results in harm to load customers. For example, in paragraph 620 of AUC Decision 22942-D02-2019[1], the AUC included the AESO's recognition of the AMP's limitation:

   […]

   (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****. … (emphasis added)*

2. **Do you agree that the issue of billing determinant erosion due to the AESO's current measurement practice, and the resulting impact of that erosion on rates and cost allocation, needs to be addressed? Why or why not?**

   AML agrees that load billing determinant erosion caused by DCG is currently occurring and needs to be addressed. If not sufficiently addressed, all else equal, load customers directly connected to the transmission system and DFOs with low DCG penetration will pay more for transmission service than DFOs with high DCG penetration, all of whom receive similar transmission service. Further, all else equal, because DFOs recover transmission costs from their distribution-connected load customers, distribution-connected load customers located in a DFO service territory with high DCG penetration will pay more for transmission service than distribution-connected load customers located a DFO service territory with low DCG penetration.

[1] Decision 22942-D02-2019, 2018 Independent System Operator Tariff

In paragraph 23 of AUC Decision 26090-D01-2021[2], the AUC succinctly described the problem of DCG-related billing determinant erosion which recognizes the negative impact that all DCG output has on billing determinants:

> *"If DCG is able to locate on a distribution feeder that also serves load and is able to generate electricity coincident with that load, its operation reduces the flow of energy from the transmission system to the substation. Given the current AESO tariff design and metering locations, these reduced flows serve to lower the transmission billing determinants of metered demand and energy at the substation. Since a considerable portion of the AESO's tariff is collected from its bulk and regional charges on the basis of the monthly coincident peak of the system (12 CP), the reduction in metered demand coincident to the peak can significantly reduce the bill received by the distribution utility from the AESO for transmission service due to the presence of DCG on the feeder."*

It seems the AUC recognized the full extent of the problem and would possibly support a remedy that is blind to whether the impact of DCG occurs above or below the feeder level.

It is well-documented that distribution-connected load customers receive similar transmission services as load customers who are directly connected to the transmission system. These services include but are not limited to: reliability; load following and equipment start-up power; frequency and voltage support; and, most importantly, access to contracted, wholesale and retail energy transactions. Pages 16-20 of the EPRI report[3], which was submitted during the AESO 2018 ISO Tariff proceeding[4] and the AUC's Distribution System Inquiry[5], discusses these benefits in more detail. For distribution-connected load customers to potentially pay less for the same transmission service, simply as a result of something like high levels of DCG, is unfair and represents a form of cross-subsidization.

In the *"Adjusted Metering Practice - Q&A Session and Question Board Summary and AESO Replies*" AML notes the responses to AML's questions labeled # 10, 11 on page 4, paragraph 3, where the AESO states:

> *"More specifically, the AMP is not meant to address the billing determinant erosion due to a reduction of flows because load is being served by DCG <u>on the same feeder</u>. The AESO only provides system access service at a point of connection to the transmission system and does not provide service downstream of a point of connection to the transmission system…"*

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[2] Decision 26090-D01-2021, Distribution-Connected Generation Credit Module for Fortis's 2022 Phase II Distribution Tariff Application, PDF page 5

[3] The Integrated Grid, Realizing the Value of Central and Distributed Energy Resources

[4] Exhibit 22942-X0448

[5] Exhibit 24116-X0179

AML respectfully disagrees with this response. First, DCG does not serve the load on the feeder or provide the grid services mentioned in the EPRI report that are provided by the transmission system. Second, the transmission system does provide services downstream of the point of connection; this is the very nature of the benefits of a networked system which can only be provided by the transmission system.

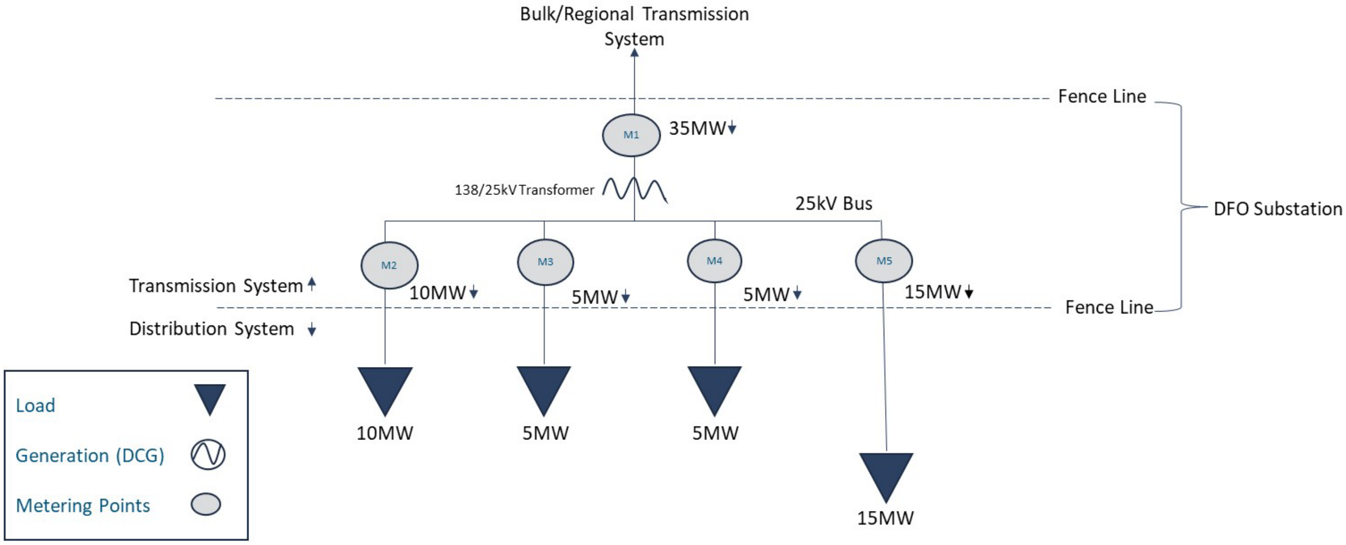
In the absence of DCG or behind-the-meter generation generally, metered flows (i.e., capacity (MW) and energy (MWh)) can act as a reasonable proxy for assessing the use of the transmission system by load. However, if the billing determinants do not accurately reflect the total potential load that uses the transmission system, then using flows as a billing determinant will be flawed; and further, any tariff design that uses these determinants (i.e., flows) will also be flawed.

3. **The AESO has described the challenges in creating an accurate impact analysis in [Section 3]. Do you have any concerns, suggested improvements or different approaches to the impact analysis that has been carried out by the AESO, in light of the challenges the AESO has described? If yes, please explain.**

AML has a concern with the AESO's impact analysis. AML considers that **all** DCG can cause an erosion of the DFO load billing determinants and therefore **all** DCG should be accounted for when completing any analysis. The AESO's analysis, as currently presented, only accounts for netting of load and DCG flows occurring at the feeders if it registers a negative flow at the substation (i.e., flow into the substation from a DFO feeder). This analysis does not account for the netting of load and DCG flows occurring downstream of the feeders where DCG nets with the load before entering the substation.

AML considers the level of billing determinant erosion occurring is substantially higher than the AESO has estimated. As an example of the billing determinant erosion not currently being accounted for by the AESO, below is a before (Figure 1 a, b, c) and after (Figure 2 a, b, c) scenario highlighting this situation. Figure 1a demonstrates a Base Case Scenario where the DTS billing determinants for a DFO substation is only serving load; Figure 1b shows the Base Case Load Profile; and Figure 1c shows the Base Case Billing Information for this substation. Figure 2a is the same substation but with a DCG added at some future date on a distribution feeder just outside the substation, with Figure 2b showing the impact this added DCG will have on the load profile and Figure 2c showing the impact to the substation billing information.

Figure 1a – Base Case Scenario



Note: Loads on individual feeders could be single loads or comprised of multiple loads dispersed amongst the distribution system

Figure 1b – Base Case Load Profile

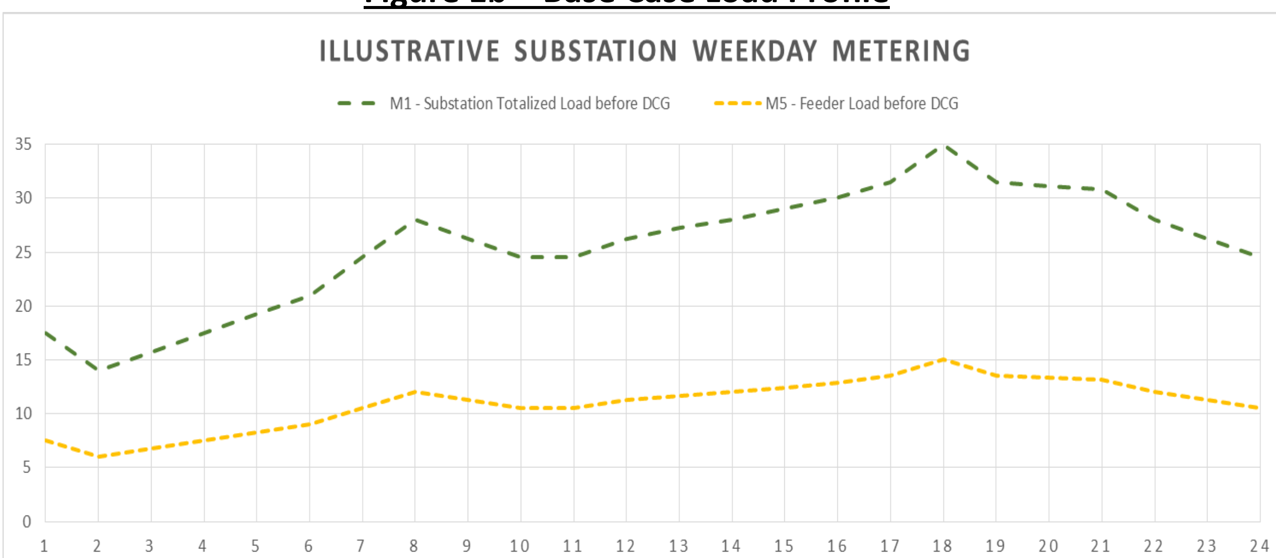


Figure 1c – Base Case Substation Billing Information
Metering Point M1

Rate DTS Bill Estimate Under ISO Tariff

Tariff:	AESO 2023
Effective:	Jan 01, 2023
To:	current

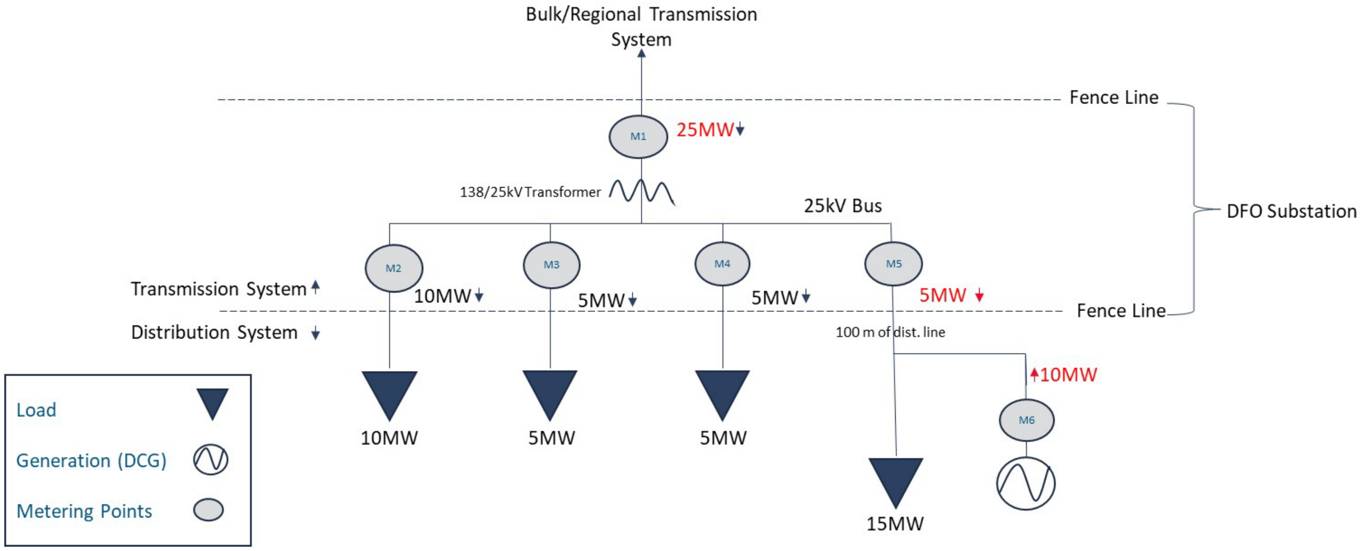
	Billing Quantity	Reference	Volume
	Contract Capacity		35.0 MW
(j)	Substation fraction (SF)	Glossary	1.00000
(k)	Highest metered demand	Glossary	35.0 MW
(m)	Coincident metered demand	DTS:3(2)	26.3 MW
(o)	Billing capacity	Glossary	35.0 MW
(r)	Metered energy	Glossary	16,608 MWh
(s)	Pool price	Glossary	$94.34 /MWh
(t)	% of pool price for operating reserve charge	DTS:4(2)	5.18%
(u)	Apparent power difference	DTS:7(b)	0.0 MVA

Rate or Rider Component		Charge	Volume	Amount
Rate DTS: Demand Transmission Service				
Connection Charge				
Bulk System Charge				
3(1)(a)	Coincident metered demand	$10,840.00 /MW/month	26.3 MW	$284,550
3(1)(b)	Metered energy	$1.18 /MWh	16,608 MWh	$19,597
Regional System Charge				
3(1)(c)	Billing capacity	$2,844.00 /MW/month	35.0 MW	$99,540
3(1)(d)	Metered energy	$0.90 /MWh	16,608 MWh	$14,947
Point of Delivery Charge				
3(1)(e)	Substation fraction	$14,728.00 /month	1.00000	$14,728
3(1)(f)	First (7.5 × SF) MW of billing capacity	$4,847.00 /MW/month	7.5 MW	$36,353
3(1)(g)	Next (9.5 × SF) MW of billing capacity	$2,875.00 /MW/month	9.5 MW	$27,313
3(1)(h)	Next (23 × SF) MW of billing capacity	$1,924.00 /MW/month	18.0 MW	$34,632
3(1)(i)	All remaining MW of billing capacity	$1,185.00 /MW/month	0.0 MW	$0
Operating Reserve Charge Estimate				
4	Metered energy pool price × 5.18% =	$4.89 /MWh	16,608 MWh	$81,158
Transmission Constraint Rebalancing Charge Estimate				
5	Metered energy	$0.017 /MWh	16,608 MW	$282
Voltage Control Charge				
6	Metered energy	$0.09 /MWh	16,608 MWh	$1,495
Other System Support Services Charge				
7(a)	Highest metered demand	$24.00 /MW/month	35.0 MW	$840
7(b)	Apparent power difference	$400.00 /MVA/month	0.0 MVA	$0
Total Rate DTS charge				**$615,433**

Total estimated charge - Monthly - Rate DTS: $615,433

Total estimated charge - Yearly - Rate DTS: $7,385,200

Figure 2a – Base Case Plus DCG Scenario



Notes:

i. This scenario depicts a single DCG unit, however this could be comprised of multiple DCG units dispersed widely on the distribution system

ii. The 35 MW of load served by this substation is indifferent (i.e., receives the same transmission service) as to how the DCG is connected, either a) by its own substation off the transmission system or b) directly connected off the distribution feeder. However, the 35 MW of load will be billed less for transmission service in the situation where it is served off the feeder.

Figure 2b – Base Case Plus DCG Load Profile

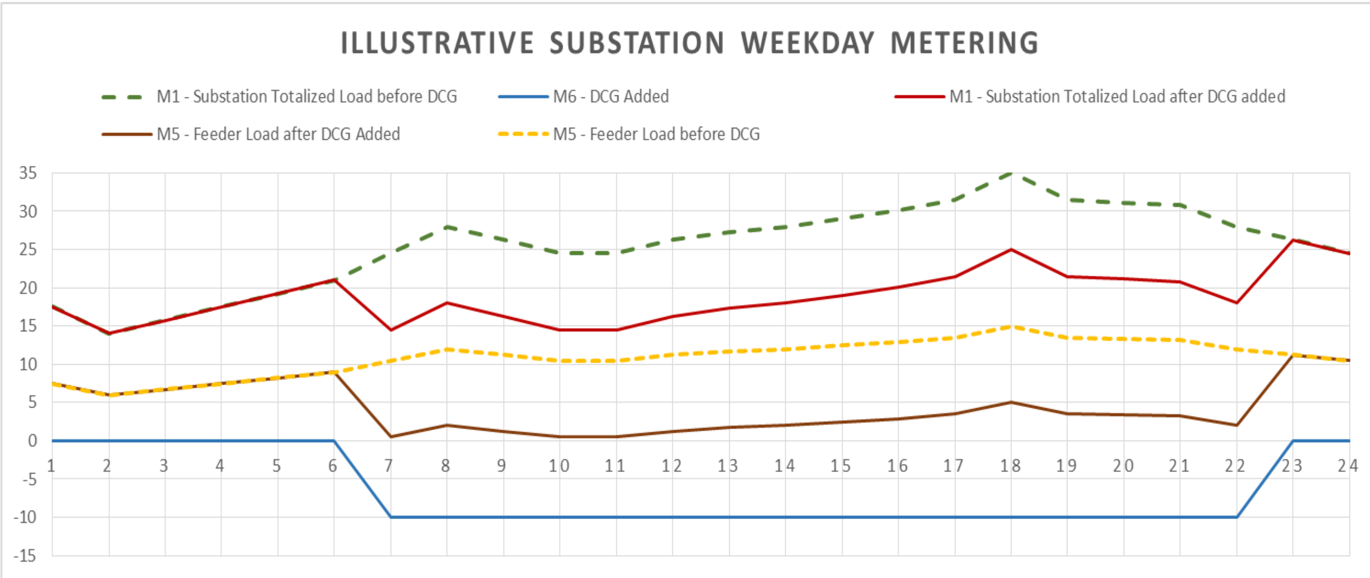


Figure 2c – Base Case Plus DCG Substation Billing Information
Metering Point M1

Rate DTS Bill Estimate Under ISO Tariff

Tariff:	AESO 2023
Effective:	Jan 01, 2023
To:	current

	Billing Quantity	Reference	Volume
	Contract Capacity		35.0 MW
(j)	Substation fraction (SF)	Glossary	1.00000
(k)	Highest metered demand	Glossary	25.0 MW
(m)	Coincident metered demand	DTS:3(2)	18.8 MW
(o)	Billing capacity	Glossary	31.5 MW
(r)	Metered energy	Glossary	11,863 MWh
(s)	Pool price	Glossary	$94.34 /MWh
(t)	% of pool price for operating reserve charge	DTS:4(2)	5.18%
(u)	Apparent power difference	DTS:7(b)	0.0 MVA

Rate or Rider Component		Charge	Volume	Amount
Rate DTS: Demand Transmission Service				
Connection Charge				
Bulk System Charge				
3(1)(a)	Coincident metered demand	$10,840.00 /MW/month	18.8 MW	$203,250
3(1)(b)	Metered energy	$1.18 /MWh	11,863 MWh	$13,998
Regional System Charge				
3(1)(c)	Billing capacity	$2,844.00 /MW/month	31.5 MW	$89,586
3(1)(d)	Metered energy	$0.90 /MWh	11,863 MWh	$10,676
Point of Delivery Charge				
3(1)(e)	Substation fraction	$14,728.00 /month	1.00000	$14,728
3(1)(f)	First (7.5 × SF) MW of billing capacity	$4,847.00 /MW/month	7.5 MW	$36,353
3(1)(g)	Next (9.5 × SF) MW of billing capacity	$2,875.00 /MW/month	9.5 MW	$27,313
3(1)(h)	Next (23 × SF) MW of billing capacity	$1,924.00 /MW/month	14.5 MW	$27,898
3(1)(i)	All remaining MW of billing capacity	$1,185.00 /MW/month	0.0 MW	$0
Operating Reserve Charge Estimate				
4	Metered energy pool price × 5.18% =	$4.89 /MWh	11,863 MWh	$57,970
Transmission Constraint Rebalancing Charge Estimate				
5	Metered energy	$0.017 /MWh	11,863 MW	$202
Voltage Control Charge				
6	Metered energy	$0.09 /MWh	11,863 MWh	$1,068
Other System Support Services Charge				
7(a)	Highest metered demand	$24.00 /MW/month	25.0 MW	$600
7(b)	Apparent power difference	$400.00 /MVA/month	0.0 MVA	$0
Total Rate DTS charge				**$483,640**

Total estimated charge - Monthly - Rate DTS: $483,640

Total estimated charge - Yearly - Rate DTS: $5,803,681

When comparing the two scenarios above, it is apparent that the addition of DCG can have a significant impact on the billing determinants and resulting bills to be paid by a DFO. The analysis shows that approximately **$ 1.6 million/year** or a **21%** loss of revenue will occur when a DCG of this type is added at this substation. This foregone revenue must then be recovered from all transmission-connected load customers including other DFOs with lower levels of DCG (the other DFOs will recover their portion of this foregone revenue from distribution-connected load customers who reside in their service territories).

AML suggests the AESO analyze the impact that DCG has on each individual DFO substation's billing determinants and calculate the foregone revenue occurring at each site. This analysis should be relatively straightforward to complete as the AESO has totalized interval metered data at all DFO substations and has indicated that it has individual interval metered data for a substantial amount of the DCG. This analysis, complete with any associated spreadsheets, should then be provided to stakeholders as part of the consultation process.

In lieu of a broader detailed analysis, AML performed the following high-level estimate of province-wide billing determinant erosion and the associated revenue impact:

The AESO indicates in slide 7 of its "Background and Ongoing Need" deck that installed DCG capacity was approximately 650 MW in 2018; and in slide 15 of the same deck, current installed DCG capacity is 1,438 MW. As shown in Table 1 of AUC Decision 26090-D01-2021[6], DFOs paid $28.2 million to DCGs in 2018. If we assume the DCG credits paid by the DFOs to DCGs were reflective of the billing determinant erosion occurring and then adjust the 2018 amount paid by DFOs to DCGs to 2022 (i.e., 1,438 MW/650MW), the current foregone revenue due to DCG billing determinants erosion is approximately $60 million. For comparison purposes, slide 11 of the AESO's "Impact Analysis" deck shows that the AESO's AMP proposal only captures approximately $16 million worth of the billing determinant erosion that is currently occurring. This represents a significant difference in foregone AESO tariff revenue, and AML suggests that its estimate of $60 million could be conservative.

As an alternative to the current AMP approach proposed by the AESO, <u>AML proposes a Billing Adjustment approach to correct the DCG-related billing determinant erosion in more appropriate and complete manner than AMP without incurring the additional cost of installing meters</u>. Under the proposed Billing Adjustment approach, the AESO would sum the interval metered data for each DCG connected to a particular substation which will then provide an accurate assessment of the level of erosion that has occurred to the substation load billing determinants. Adding the summed DCG data back to the substation totalized metered data will provide correct load billing determinant adjustments and allow the AESO to collect otherwise forgone tariff revenue resulting from DCG-related billing determinant erosion.

[6] Decision 26090-D01-2021, Distribution-Connected Generation Credit Module for Fortis's 2022 Phase II Distribution Tariff Application, PDF page 9

The following is an illustrative example of the Billing Adjustment approach discussed above. (See ***Figure 2_Base Case Plus DCG Scenario*** above for reference)

Corrected Substation metering = M1 + M6
= 25MW + 10 MW = 35 MW
= substation metering prior to the addition of DCG

4. The AESO has described the challenges in obtaining the AACE Class 3 cost estimates directed by the Commission in Decision 27047-D01-2022. The AESO has also described how it arrived at a theoretical maximum cost to implement the AMP, and existing capital cost oversight mechanisms that could be used for AMP implementation. Do you have any concerns with or suggested improvements to the foregoing? If yes, please explain.

AML has proposed an alternative solution to the AESO's AMP proposal which does not require the installation of new feeder-level meters. Therefore, AML has no comment with respect to the AESO's cost estimates for AMP. As AML has discussed above, a more accurate assessment of billing determinant erosion should be completed, and AML considers this type of analysis could be translated into an administrative model that can be used for determining accurate billing determinants in real time for each individual substation. With the AESO having the appropriate metering point data available to it, the costs to implement should be minimal as it is anticipated that only administrative procedures and perhaps billing engine upgrades would be required.
With respect to the feasibility of implementing AML's proposed alternative to AMP, AML notes the AESO's following assertion made in a response included in the *"Adjusted Metering Practice - Q&A Session and Question Board Summary and AESO Replies*":

> *"The installation of meters at the feeder connection in a substation is the only option for implementing the AMP (subject to legacy treatment considerations). The individual energy flows into and out of a substation on each feeder are required to produce the necessary measurement data and cannot be accurately extrapolated using other metered data available to settlement, due to issues with non-interval meters, distribution line losses, unaccounted for energy, different meter data managers (MDM), and the need to use deductive totalization against the transformer meter (a practice prohibited by Measurement Canada)."*

AML respectfully disagrees with this assertion as it considers an administrative solution exists to address billing determinant erosion. The DFOs, for example, have long been able to administratively calculate DCG credits by combining the necessary measurement data available from the substation and the DCG metering points to determine the billing determinants required to calculate a DCG credit. AML considers a similar process (in reverse) could be used to implement its proposed alternative.

AML submits the AESO should not proceed with its proposed AMP until an alternative administrative solution is thoroughly investigated and results shared with stakeholders.

5. **If you support implementing the AMP, do you support implementing it with legacy treatment or without legacy treatment? Please explain.**

   AML does not support legacy treatment of incorrect load billing determinants for DFO substations as the typical bill impact on load customers served from a distribution system will likely be below 10%. If, however, the AESO indicates the typical bill impact is potentially greater than 10%, then the AESO should perform and share a typical bill analysis as part of the stakeholder process.

6. **If you support implementing the AMP, do you support implementing it in a manner that prioritizes the minimization of costs that would be recovered through ISO tariff rates. Why or why not? Are there other objectives that should be taken into account or prioritized by the AESO?**

   As should be evident by its proposed alternative to AMP, AML supports implementing a means for resolving billing determinant erosion that emphasizes minimization of implementation costs that would be recovered through ISO tariff rates, especially when the proposed alternative to AMP more thoroughly resolves the problem of billing determinant erosion.

AMP Implementation

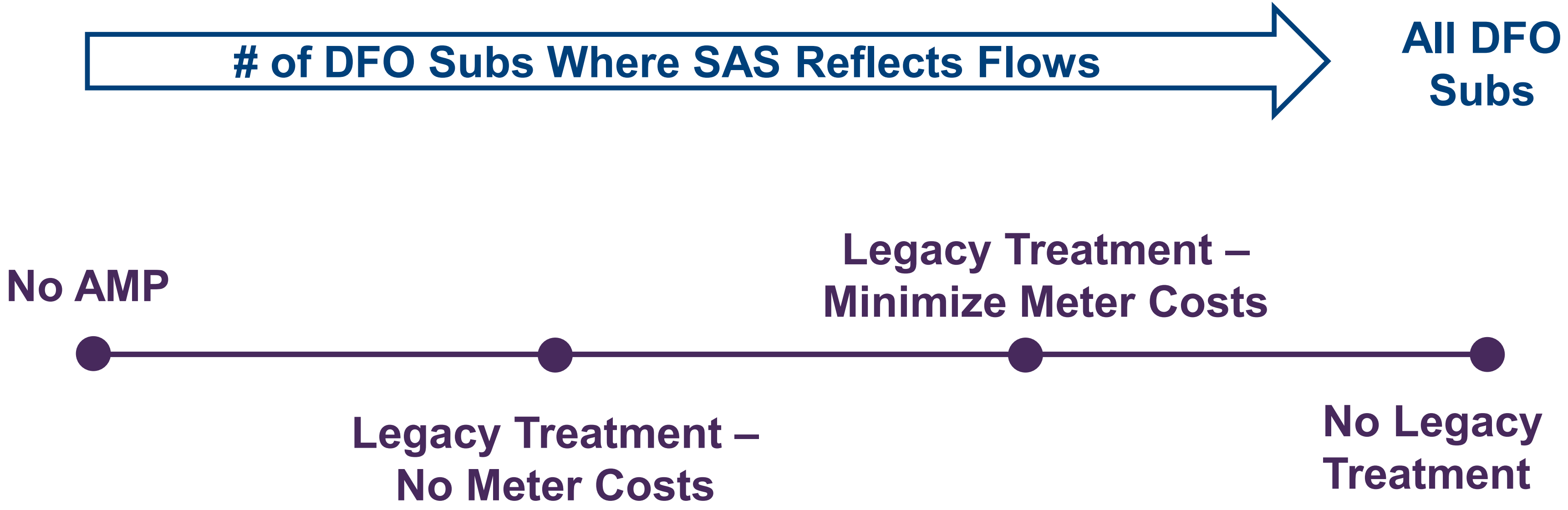
Minimize or Eliminate the Meter Costs

May 2023

Purpose of One-on-One Meetings

- The AESO continues to see value in implementing the AMP
- Main theme we've heard from stakeholders: Concerns with the costs associated with implementing the AMP without legacy treatment
- As a result, we want to discuss how to minimize/eliminate metering costs by providing legacy treatment to some substations
  - What does "legacy treatment" mean? AMP tariff provisions would require that SAS reflect flows to/from the transmission system at the feeder level. "Legacy treatment" would exempt certain substations from complying with those provisions (i.e. SAS would not have to reflect the flows)
  - What are the areas of concern and tradeoffs to consider for each stakeholder
- Totalized billing concerns?
- Discuss specific stakeholder feedback

Paths Forward For the AMP



How Should We Choose Which Path To Take?

The AESO has identified the following principles to assess the different paths for implementing the AMP:

1. SAS should accurately reflect flows to/from the system for all MPs
2. The AESO can't retroactively charge MPs for connection costs after connection decisions have already been made
3. Legacy treatment should be limited in number and duration
4. Decisions about SAS and connections are up to the MP, but they must be aware of costs and consequences/impacts of these decisions
5. Current rate design for DTS and STS both require measured BDs; however, future DTS re-design requirements are unknown

Objective: Balance affordability, economic efficiency and fairness

Path Discussion

Explain the Paths:

- What actions are required for existing reversals (namely Category B & C)
- How to treat new reversals in the future (Phase 3)

Discuss:

- Tradeoffs for affordability, economic efficiency, and fairness
- When should the AMP become effective?
- Requirements for new substations and existing substations undergoing major alterations?

Paths

	No AMP	Legacy Treatment – No Meter Costs	Legacy Treatment – Minimize Meter Costs	No Legacy Treatment
Existing Reversals: Cat B (feeder meters)	No actions required	Administrative actions to implement AMP	Administrative actions to implement AMP	Administrative actions to implement AMP
Existing Reversals: Cat C (transformer meters)	No actions required	Provide legacy treatment	Provide legacy treatment	Physical actions to implement AMP (install meters)
Future Reversals: Phase 3	No actions required	Either no STS if physical changes required (i.e. restrict SAS) or don't make physical changes for new STS (i.e. provide legacy treatment)	Decision to take new STS is up to DFO – if new meters are required, then costs are participant-related	Decision to take new STS is up to DFO – if new meters are required, then costs are participant-related

Timing of AMP

- How much time do DFOs require to do feeder analysis and advise of SAS contract capacities?
- DCG credit phase-out timing
  - Jan 1, 2024 multiplier: 0.4
  - Jan 1, 2025 multiplier: 0.2
  - Jan 1, 2026 multiplier: 0
- B&R rate design
  - Billing determinants for future design unknown
  - STS not being re-designed
- On-going (growing) misallocation each year

New Substations and Major Alterations

- Should feeder-level meters be required at all new substations?
- Should feeder-level meters be required if the TFO is undergoing major alterations anyways?
- What if the minimum requirement is just the infrastructure for feeder-level meters?
  - Meters can be installed at some point in the future, when there are reversals

Totalized Billing at A Single Substation

- Any concerns?

Notice

To: Market participants and other interested parties (Stakeholders)

Date: August 9, 2023

Subject: Notice of Alberta Electric System Operator (AESO) and Alberta Utilities Commission (AUC) Technical Meeting regarding the Adjusted Metering Practice (AMP)

Please be advised that, in the interests of regulatory efficiency, AESO and AUC staff will hold a technical meeting on August 15, 2023 regarding the AMP implementation plan. AUC Commission members will not attend this meeting. During the meeting, AESO staff will present on the various alternatives that have been discussed with Stakeholders and respond to clarifying questions from AUC staff. No new information will be presented beyond that which has previously been included in the AESO's stakeholder sessions. Following the meeting, minutes will be posted to the AESO Engage site and will also be included as part of the consultation record in the AESO's application.

Should you have any questions or concerns, please contact Gillian Barnett at Gillian.Barnett@aeso.ca or Kristjana Kellgren at Krisjana.Kellgren@auc.ab.ca.

Meeting Minutes

Adjusted Metering Practice (AMP)

Minutes from meeting of AUC and AESO staff

Location: Virtual Meeting
Date: August 15, 2023
Time: 10:00 a.m. to 12:00 p.m.

Attendees:

Alberta Utilities Commission (AUC) Staff	Alexey Starkov
	Cameron Strasser
	Carl Fuchshuber
	Kristjana Kellgren
	Nicole Morter
Alberta Electric System Operator (AESO)	Annie Nguyen – Senior Tariff Design Analyst
	Brij Modha – Regulatory Analyst
	Spencer Hall – Tariff Manager
	Tom Sloan - Legal Manager, ISO Tariff and Market Rules

Meeting Minutes

Introductions and Opening Remarks:

- The AESO described the stakeholder engagement that had taken place since the issuance of AUC Decision 27047-D01-2022, including materials that were posted in May 2023 used to guide the individual discussions held with stakeholders to better understand and address their concerns. These conversations, carried out in May and June, led the AESO to revise its recommended approach to AMP implementation.
- The AESO and AUC staff discussed the AESO's view of the benefits of AMP implementation, to address artificial billing determinant erosion caused by inaccuracies in the mathematical representation of flows within the current measurement practice.
- The AESO confirmed that it intended to move forward with the filing of a revised AMP implementation plan.

Discussion on Billing Determinant erosion:

- The AESO presented details about the AMP implementation, focusing on billing determinants.
- The AESO and AUC staff discussed how the primary intent of the AMP is to address artificial billing determinant erosion, and to correct inaccuracies caused by the current measurement practice in light of increasing two-way flows.
- The AESO representative detailed how the current method for measuring flows was created some time ago when two-way flows weren't common. This method has become problematic due to two-

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way flows becoming more common and larger in magnitude, leading to "artificial erosion" of billing determinants.

- Historical data analysis showed that the impact of billing determinant erosion on rates was around 3%, resulting in significant misallocation of costs under Rate DTS and Rate STS.

Discussion on Estimated Billing Determinants:

- The representatives discussed the AESO's assumptions concerning billing determinants and the consideration of obtaining more detailed information for improved accuracy. The AESO representative explained that acquiring such data from DFOs posed challenges due to its complexity, volume, and dynamic nature. To address these challenges, the AESO developed a methodology involving the resettlement of historical billing to reflect the AMP's impact, which shows that the AMP would resolve approximately $16 million in misallocations across transmission market participants. This approach took into consideration the impact on AMP rates and their effect on billing. The AESO explained that the DCG credit calculations were useful as a secondary check but were not used in place of the AMP methodology that the AESO developed.
- The representatives discussed stakeholders' concerns about the AESO's approach to assessing the impact of the AMP upon billing determinants. The AESO explained that most stakeholders found the March 2023 Q&A session to be acceptable. Two stakeholders, however, had concerns. These stakeholders initially questioned why the DCG credit calculation was not used. After discussing how the AESO recalculated and moved away from the DCG credit approach, one was satisfied with the explanation and found the numbers reasonable. The other asked the AESO to provide additional details about the methodology, so the AESO clarified that a detailed methodology will be included in their forthcoming application to provide a step-by-step explanation of the process.

Alternatives for AMP Implementation:

- The AESO representative discussed the three alternatives to AMP implementation that were included in the May 2023 materials used to guide the one-on-one discussions with stakeholders.
- The representatives discussed whether the AESO's initial choice of the no legacy treatment approach was based on preference or directive. The AESO representative clarified that the choice was made based on their understanding of the AUC’s direction from Decision 25848-D01-2020.
- The representatives discussed if the “grandfathering” previously considered by the AUC in past AMP-related AUC decisions is the same as the “legacy treatment” that the AESO will be proposing in its new implementation plan . The AESO representative clarified that the AESO was using the terms synonymously, although the extent of the legacy treatment to be included in the upcoming filing is different from the previously considered legacy / grandfathering treatment. The AESO clarified that providing legacy treatment at a substation with 2 way flows results in legacy treatment for the market participant(s) at that substation because it would not be possible to provide SAS at that substation in a manner compliant with the AMP if the appropriate meters aren’t there. Representatives discussed how a DCG at a substation that has legacy treatment for AMP would be treated differently compared to a substation without legacy treatment for AMP. Representatives discussed treatment of DCG credits and the flow-through of STS charges in this context. Substations with legacy treatment benefit DCG who currently receive DCG credits as the DCG credit that they receive will be higher. Representatives discussed how the AESO’s actual DTS bill is an input into the DCG credit calculation, so an increase to the AESO DTS bill amount would directly lead to a lower DCG credit amount. Representatives also discussed how under the AMP, there would be more DFO Rates STS billing, which would then be flowed-through to the downstream DCG.
- Representatives discussed the connection between AMP and DCG credits in the DCG credit calculation, and that the significance of this connection seems to be diminishing, especially considering the upcoming removal of DCG credits. The AESO representative clarified that the

phase-out of DCG credits does not, however, impact the need for the AMP, because the relationship between the AMP and DCG credits is “one-way”, the AMP will directly impact the DCG credit calculations, but DCG credits will not directly impact the need for AMP.

- Regarding context for legacy treatment, the AESO representative explained in Alberta, there are 70 substations equipped with meters at the transformer level. However, to comply with the AMP, those substations need to be retrofitted with meters at the feeder level. This retrofit process involves significant costs due to space constraints and the need to reconfigure existing setups. This does not mean that all 70 substations would be non-compliant with the AMP. If there are only one-way flows at one of these substations, then they are inherently compliant with the AMP because no netting can occur to misrepresent the flows. The AESO identified that of the 70 substations without feeder-level metering, they estimate only between 5 – 12 have two-way flows.
- The AESO representative explained that one of the alternatives for AMP implementation that was explored would be to provide legacy treatment at DFO substations where reversing flows already occur but the appropriate feeder level metering is not in place. Then, on a go-forward, if there are new reversing flows, typically due to new DCGs, then the DFO would submit a system access service request to the AESO, triggering the need for transmission alterations to install the meters to measure those reversed flows. This approach would incur connection costs to install the meters before the AESO would provide the requested service. Representatives discussed how this approach is meant to align with the AESO’s current connection process where transmission alterations are undertaken in response to a request for new or amended SAS.
- Representatives discussed a scenario involving a new DCG that influences the flow on one feeder, and whether this would necessitate meters on all feeders or just the specific one affected by the new DCG. Also discussed was whether the metering calculations could be carried out using the existing transformer meter along with the single meter on the feeder with DCG.
  - However, representatives discussed that feeders on the same bus must operate collectively. This means that if metering is installed for one feeder on a particular bus, it needs to be installed for all feeders on that same bus due to Measurement Canada requirements on where meters must be installed and what metering calculations are allowed. However, at substations where multiple buses exist, meter installation would not occur at all busses. Rather, meters would be installed on the busses where there are reversals. Measurement Canada prohibitions would not allow the deductive totalization that would occur if both a meter on the transformer along with a single downstream meter on a feeder were used to determine the transmission flows.
- Representatives discussed how the cost of retrofitting a substation could be flowed through to DCG customers, but that those questions are ultimately DFO tariff issues that the Commission has previously determined should be left to the DFO tariff.
- Representatives also discussed an alternative for implementation that would lower the cost of implementation by allowing for additional legacy treatment. Under this alternative, the AESO would provide legacy treatment at substations where there are already reverse flows, for the same reason as the second alternative. However, under this alternative, the AESO would also allow legacy treatment for future reversals because the trigger to install meters at the feeder level would be when the substation undergoes substantial alterations. At that point the installation of the meters would be minimal cost.
  - The AESO representative clarified that though this alternative would lower the cost of implementation by making the installations more cost-efficient, there would be inaccurate system access service billing at some substations until the appropriate meters are installed. One of the reasons why this tradeoff could be reasonable is that the AESO didn’t expect a large portion of the 70 substations to reverse, and if they did, the amount of reversals would not be significant. The AESO confirmed that discussion with DCG and DFO stakeholders had taken place, to understand the likelihood of additional reversals in the urban areas where the 70 substations are located and, based on this discussion, it was the AESO’s understanding

increasing reversals are not likely to occur. This is due to the large amount of load served at these substations, which is expected to increase over time, along with the challenges of locating large DCG in the urban areas.

- The representatives discussed scenarios concerning substations approaching their end of life, undergoing upgrades, or conversions, and the potential implications of AMP implementation on triggering additional work. The discussion focused on seeking clarification regarding the threshold for triggers for such work, especially in cases where seemingly minor changes like switch replacements could lead to more extensive rebuilding due to AMP.
  - The AESO representative explained that they had engaged in discussions with TFOs about this matter. Together, they determined a minimum threshold for triggering AMP-related work, which is the replacement of switchgear. This threshold will be formalized and included in the ISO rule.
  - The AESO representative explained that, given this threshold, TFOs expected the incremental cost of implementing AMP to be minimal to none.

Costing Direction from AUC Decision 27047-D01-2022

- Representatives discussed how the AESO intends to address the costing direction from AUC Decision 27047-D01-2022,. The AESO asked TFOs to provide high-level cost estimates for retrofitting substations, emphasizing that this was a theoretical exercise, and they were not initiating any projects or issuing direction letters to get substation specific estimates.
  - The AESO discussed how it would be addressing the direction from AUC Decision 27047-D01-2022 in its upcoming application.

Anticipated Regulatory Process

- The AESO representative acknowledged the extensive stakeholder engagement and regulatory history that has already taken place. Following the filing, they anticipate a written process involving Information Requests (IRs) and potentially other written steps. Additionally, they mentioned their openness to technical sessions if they can enhance regulatory efficiency or address confusion, although they aren't certain if it would be necessary given the substantial engagement conducted so far.
- Representatives discussed the scope of the upcoming filing, and the benefit of including an issues list within the AESO's application, together with any submissions on preferred process, or specific dates when the AESO might be unavailable.

Notice

To: Market participants and other interested parties (Stakeholders)

Date: July 21, 2023

Subject: AMP – July 2023 AESO Background and Update to Stakeholders

Stakeholder Engagement Subsequent to AUC Decision 27047-D01-2022

- On March 6, 2023, the AESO posted written materials regarding the continued need for the AESO's adjusted metering practice (**AMP**), and potential options for implementing the AMP as a result of AUC Decision 27047-D01-2022.[1] The AESO also opened a Question Board and received over 50 submissions over the course of March 2023. By April 6, 2023 the AESO posted replies to all questions posted on Question Board.
- On March 23, 2023, the AESO hosted a Virtual Q&A Session to provide stakeholders with an opportunity to discuss questions or concerns and to explore areas where clarification is still required on the AMP.
- Following the completion of the Virtual Q&A Session, the AESO posted supplemental material regarding the AMP and extended the deadline to submit written feedback by interested stakeholders until April 21, 2023. From this written feedback, it was apparent that stakeholders remained concerned with the costs of implementing the AMP, particularly if the AMP were to be implemented without legacy treatment.
- Other concerns that the AESO heard from stakeholders included the accuracy of the impact analysis conducted by the AESO for the AMP, the accuracy level of cost estimates associated with AMP implementation, the recovery of the costs installing AMP-compliant metering, and the timing of the AMP with respect to the DCG credit phase-out and other ISO tariff initiatives.
- In consideration of stakeholder concerns, the AESO indicated that it would continue to explore alternative paths to implement the AMP in order to minimize or eliminate the costs associated with the AMP.
- In May, June and July 2023, the AESO held one-to-one meetings with stakeholders that had previously provided feedback on the AMP, to understand if there were any approaches to AMP implementation that would address their concerns about costs. View materials discussed at these meetings here. The AESO held one-to-one meetings with the following stakeholders:
    - Alberta Direct Connect Consumer Association (ADC)
    - AltaLink Management Ltd.
    - ATCO Electric Ltd.
    - Capital Power Corporation
    - ENMAX Corporation
    - EPCOR Distribution & Transmission Inc.
    - FortisAlberta Inc.
    - Lionstooth Energy
    - The City of Lethbridge (including Chymko Consulting Ltd.)

[1] AUC Decision 27047-D01-2022, *Alberta Electric System Operator Application for Approval of the Adjusted Metering Practice Implementation Plan and Associated Section 502.10 of the ISO Rules* (May 31, 2022).

- The City of Red Deer (including Chymko Consulting Ltd.)
- The DCG Consortium
- The Industrial Power Consumers Association of Alberta (IPCAA)
- The University of Alberta (including Chymko Consulting Ltd.)
- Verisorium Energy Ltd.

The AESO also encouraged other interested stakeholders to contact the AESO if they wished to discuss the AMP with the AESO. However, no other stakeholders contacted the AESO.

Proposed Approach to AMP Implementation and Application

- In response to stakeholder feedback and as a result of the AESO's one-on-one meetings with stakeholders, the AESO has decided in its upcoming AMP application to propose to implement the AMP with legacy treatment, as follows:

(i) Upon the AMP becoming effective (i.e., approved for implementation by the Alberta Utilities Commission (**Commission**), for all existing substations that connect to an electric distribution system (**DFO Substations**) with reversing flows and revenue meters at the feeder level, administrative actions would be taken by the AESO to implement the AMP. This administrative work would consist of updating Measurement Point Definition Records, data systems, and system access service agreements to align with the AMP.

(ii) However, for existing DFO Substations that have reversing flows but do not already have revenue meters at the feeder level, legacy treatment would be provided. In other words, these DFO Substations will not be required to immediately comply with the AMP.

(iii) New revenue metering requirements would be incorporated into Section 503.17 of the ISO Rules, *Revenue Metering System* (**Section 503.17**), to require:

a. For new DFO Substations, at a minimum, infrastructure capable of feeder level metering so that revenue meters can be easily installed if and when there are reversing flows.

b. For existing DFO Substations that currently have revenue meters at the transformer level, the installation of either the infrastructure capable of feeder level metering or the complete revenue metering system at the feeder level installed at such time as the substation is required to undergo significant lifecycle alterations or rebuilds. At that point, the incremental cost of installing a revenue meter system at the feeder level would be negligible since the substantive work and costs associated with retrofitting the substation would be occurring for the lifecycle alteration or rebuild anyways.

See the AESO's Associated Rule Revisions posted on the Adjusted Metering Practice AESO Engage page for details of the proposed amendments to 503.17.

(iv) Section 3 of the ISO tariff will be revised to require contract capacities for new or modified system access service in a manner to align with the AESO's AMP proposed approach; i.e., to require AMP compliant contract capacities, except at DFO Substations where legacy treatment has been provided.

a. If a market participant is requesting new or amended system access service at a DFO Substation that already has a revenue metering system at the feeder level, or at least has the infrastructure capable of feeder level metering, then new or amended system access service can be contracted, measured, and billed in a manner compliant with the AMP.

b. If a market participant is requesting new or amended system access service at a DFO Substation that only has transformer level metering, and there are reversing flows at the substation, then system access service cannot be measured and billed in a manner compliant with the AMP since the revenue meters cannot easily be installed at the feeder level. In these circumstances, the ISO tariff would permit system access service to be contracted in a manner that does not align with the AMP.

See the AESO's ISO Tariff Contract Capacity Provisions on the Adjusted Metering Practice AESO Engage page for a blackline of the AESO's proposed amendments to Section 3 of the ISO tariff.

- The AESO considers it appropriate to request that the Commission approve implementation of the AMP in the manner described above with effect as of January 1, 2025.
- The AESO acknowledges that there are tradeoffs with the timing and approach described above, as it will result in legacy treatment at a small number of DFO Substations. However, it will also mean that the AMP can be implemented, and most of the AMP's benefit achieved, at no capital cost in the near-term and virtually no cost in the long-term, which was the primary concern raised by stakeholders. The AESO therefore considers this approach to be an appropriate means of moving forward with the AMP.
- Alternatively, the AMP could be implemented without legacy treatment at all DFO Substations. However, this approach would result in stand-alone capital costs to retrofit existing substation metering from transformer to feeder level and, based on recent discussion, is not supported by the majority of stakeholders.
- Based on the information currently available to the AESO, for context regarding the extent of the legacy treatment that the AESO expects to arise:
    - Of the approximately 450 DFO Substations that exist, 380 currently have feeder level meters and the remaining 70 have transformer level meters.
    - This does not mean that there would be 70 DFO Substations that are not compliant with the AMP and would require legacy treatment, because there are up to 12 DFO Substations that may currently reverse, but only approximately 5 that are *likely* to do so. As a result, the AESO expects that, under its proposed approach, legacy treatment would only be immediately required at 5 of the 450 existing DFO Substations. The remaining DFO Substations could be brought into compliance with the AMP with only administrative changes.
- While the AESO intends to propose to implement the AMP in the manner described above, the AESO also intends in its upcoming AMP application to describe the alternatives that were explored, including other methods of implementation and timing, to ensure that associated trade offs can be properly considered by the Commission.
- As part of the AESO's upcoming AMP Application, the AESO also intends to file an implementation plan, together with the ISO rule and tariff revisions, to ensure that the Commission can approve the operationalization of the AMP with legacy treatment as described above.

Revisions Required to Section 503.17 of the ISO Rules, *Revenue Metering System*

- See the AESO's July 21, 2023 Letter of Notice on the Adjusted Metering Practice AESO Engage page for a detailed description of the revisions to Section 503.17 that will be required to implement the AMP with legacy treatment.

Revisions Required to the ISO Tariff

- The Commission previously approved ISO tariff revisions to align with the AMP in AUC Decision 26215-D01-2021. However, these revisions were premised upon the Commission's prior approval of the AMP "without legacy treatment."
- To implement the AMP with legacy treatment at DFO substations, the following amendments to the ISO Tariff will be required:
  - Amend subsections 3.6(2) and 3.6(3); and
  - New subsection 3.6(5).
- Additionally, the AESO is proposing new subsection 3.6(4) to provide exemptions from subsections 3.6(2) and 3.6(3) applicable to self-supply and export.
- Amendments to subsections 3.6(2) and 3.6(3) of the ISO tariff will be required, to ensure that system access service agreements are executed at contract capacities that are based on the flows to and from the transmission system at each physical point of connection to the transmission system. For a DFO Substation, each physical connection to the transmission system is the feeder that exits the substation.
- New subsection 3.6(5) allows for legacy treatment from the AMP at DFO Substations. If the DFO Substation does not have feeder level metering or the infrastructure in place capable of easily installing revenue meters at the feeder level, then the AESO will allow an exception from subsections 3.6(2) and 3.6(3) since it would not be possible to meter the flows at the feeder level without a substantive and costly retrofit.
- New subsection 3.6(4) is not required for the AMP.[2] As discussed in paragraphs 23-37 of AUC Decision 26215-D01-2021, this provision applies to market participants that request new or amended system access service and allows exemptions from subsections 3.6(2) and 3.6(3) as a result of an approval to self-supply and export.
- A new ISO tariff definition of "revenue meter" will be required in connection with the above revisions. "Revenue meter", as already defined for the ISO rules, will be defined as "the interval meter and the associated apparatus that measures active energy or reactive energy at intervals defined by the **ISO** for the purpose of financial settlement with the **ISO**."
- Please see the Adjusted Metering Practice AESO Engage page for blacklines of the ISO tariff revisions that the AESO intends to propose as part of its upcoming AMP application.

ISO Tariff Totalized Billing Provisions

- Since 2011, the ISO tariff has totalized billing provisions as part of its terms and conditions regarding settlement. The current totalization provisions approved as part of AUC Decision 22942-D02-2019 specify that totalized billing is only permissible to points of delivery (**PODs**) (or

[2] This provision was approved by the Commission in AUC Decision 26215-D01-2021, *Alberta Electric System Operator Review and Variance of Decision 26215-D01-2021* (June 3, 2021). As described at paragraph 7 of that Decision, the Commission approved effective date of the provision to be delayed "…to a date to be specified by the Commission in its approval of the AMP implementation plan that has yet to be filed by the AESO."

points of supply (**POSs**) at *separate substations*.[3] Prior to Decision 22942-D02-2019, the totalized billing provisions were silent on whether the points of delivery (or points of supply) being totalized could exist within the same or at separate substations.

- The distinction of "separate substations" in the proceeding that led to AUC Decision 22942-D02-2019 has created a lack of clarity regarding if and how totalization within the same substation is permitted.
- Since multiple PODs (or POSs) can exist within the same substation, the ability to totalize those multiple PODs (or POSs) under the same demand transmission service (or supply transmission service) should apply.
- The totalized billing provision that the AESO is proposing to section 10 of the ISO tariff should broadly apply to all market participants, including DFOs.
  - Without the ability to totalize at the same substation, the AESO would be required to separately contract and bill for DTS (or STS) at each of the points of delivery (or points of supply) within the substation, which is administratively inefficient.
  - Additionally, not allowing the totalization of multiple points of supply in a substation would create an artificial barrier that limits the ability of a market participant to aggregate some or all of its generating units as contemplated by subsection 5 of Section 501.10 of the ISO rules, *Transmission Loss Factors*.
- The AESO intends to propose the above-described totalization billing revisions as part of the AMP application. However, as the AESO considers these revisions to be required regardless of the AMP, the AESO will be requesting that they be approved on a stand-alone basis.
- See the Adjusted Metering Practice AESO Engage page for a blackline of the revisions required to Section 10 of the ISO tariff and relating to totalized billing.

Next Steps

Prior to filing its AMP application, the AESO will be carrying out the following final consultation steps with stakeholders, as follows:

1) **July 21, 2023** – the AESO will post a letter of notice for the revisions required to Section 503.17, including a proposed draft of amendments to Section 503.17, for stakeholders' written comments;
2) **August 11, 2023** – the AESO will provide 3 weeks for stakeholders to submit written comments on the AESO's proposed approach to the AMP, including the amendments to Section 503.17, with comments due no later than August 11, 2023. The AESO will post all comments received from stakeholders. Please see the AESO's July 21, 2023 *Stakeholder Comment Matrix – Proposed Adjusted Metering Practice Implementation* on the Adjusted Metering Practice AESO Engage page
3) **Prior to August 25, 2023** – the AESO may contact stakeholders in the event of any significant and new comments or concerns are raised.
4) **August 25, 2023** – the AESO may reply to any Stakeholder comments received, and will submit its AMP application to the Commission.

[3] See AUC Decision 22942-D02-2019, *Alberta Electric System Operator 2018 Independent System Operator Tariff* (September 22, 2019).

July 21, 2023

To: Market Surveillance Administrator, market participants and other interested parties ("Stakeholders")

Re: Letter of Notice for Development of Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17")

Pursuant to Alberta Utilities Commission Rule 017, *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission* ("AUC Rule 017"), the Alberta Electric System Operator ("AESO") is providing notice and seeking feedback from Stakeholders on proposed revisions to Section 503.17.

Background

The AESO's adjusted metering practice ("AMP") is intended to ensure a more accurate measurement of flow to and from the transmission system at substations that connect to an electric distribution system ("DFO Substations").

In accordance with AUC Decision 25848-D01-2020,[1] the AESO previously proposed to implement the AMP without legacy treatment, including through revisions to Section 502.10 of the ISO rules, *Revenue Metering System Technical and Operating Requirements* ("Section 502.10").

Since that time, Section 502.10 has been renumbered to Section 503.17.[2]

Further, as described in the AESO's July 21, 2023 Background and Update to Stakeholders and in response to AUC Decision 27047-D01-2022,[3] the AESO is now proposing to implement the AMP *with* legacy treatment. To do this, revisions to Section 503.17 are required.

This letter addresses the consultation being carried out by the AESO in accordance with AUC Rule 017 for the proposed revisions to Section 503.17. For further details on the AESO's revised AMP implementation plan and upcoming AMP application, please visit the Adjusted Metering Practice AESO Engage page.

Issue

In conjunction and as part of the AESO's proposal to implement the AMP with legacy treatment, the AESO is initiating consultation on Section 503.17 in order to ensure that:

- The revenue metering system at DFO Substations allows for financial settlement as required by the ISO Tariff; and
- On a go-forward basis, for new DFO substations and existing DFO substations that undergo the installation or replacement of switchgear lineups, at a minimum, the infrastructure required for feeder level metering is installed.

[1] AUC Decision 25848-D01-2020, *Alberta Electric System Operator Stage 2 Review and Variance of Decision 22942-D02-2019 Adjusted Metering Practice and Substation Fraction Methodology* (December 23, 2020).
[2] AUC Decision 28176-D01-2023, *Alberta Electric System Operator Approval of Proposed Energy Storage Amendments to the ISO Rules* (June 13, 2023).
[3] AUC Decision 27047-D01-2022, *Alberta Electric System Operator, Application for Approval of Adjusted Metering Practice Implementation Plan and Associated Section 502.10 of the ISO Rules* (May 31, 2022).

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Purpose

To minimize capital costs associated with implementing the AMP and in response to AUC Decision 27047-D01-2022, the AESO will be proposing to implement the AMP with legacy treatment. Further, as part of the AESO's consultation with stakeholders regarding the installation of feeder-level revenue meters at new and existing DFO Substations, the AESO discussed the need for more operational flexibility and efficiency around the timing of installation.

As a result of those discussions, the AESO has determined that Section 503.17 should be revised to reflect the following:

- Revenue metering systems exist for the purpose of financial settlement with the AESO. As a result, the AESO is proposing to include new subsection 2(1) and removing existing provision 2(3) from the Measurement Point Definition Record section. The requirement that revenue meters must be operated in accordance with the measurement point definition record from existing subsection 2(3) is captured in existing subsection 5(2).
- At the time switchgear is installed or replaced at a DFO Substation, for the purposes of financial settlement with the AESO, a complete revenue metering system at the feeder level does not also need to be installed until there are reversing flows on the feeders, because it is operationally efficient to maintain fewer meters, and one-way flows from the transmission system are measured accurately with transformer meters. Consequently, the AESO is proposing to include new subsection 3(1) to require that, at the time switchgear is installed or replaced at a DFO Substation, only the installation of the *infrastructure* for feeder level metering is required This approach will provide transmission facility owners ("TFOs**"**) with the option of installing and operating fewer meters unless they are required immediately for the financial settlement required by the ISO tariff as a result of existing reversing flows.

As long as the infrastructure required for feeder level metering is in place at a DFO Substation, the revenue meters can in the future be installed at the feeder level without requiring a significant amount of work or cost. Installing this infrastructure at the time of a switchgear lineup installation can be done at minimal extra cost.

Proposed Consultation and Timeline

The AESO proposes Stakeholder consultation by way of a written process, as follows:

1. **July 21, 2023** – the AESO posts this letter of notice and attached documents, including a proposed draft of amendments to Section 503.17, for Stakeholders' written comment;
2. **August 11, 2023** – the AESO will provide 3 weeks for Stakeholders to submit written comments on drafts of the AESO's proposed amendments to Section 503.17 with comments due August 11, 2023; and
3. **On or before August 25, 2023** – the AESO will post replies to stakeholder comments and file its application for approval of proposed amendments to Section 503.17.

Stakeholder Comments

Please use the *Stakeholder Comment Matrix – Proposed Adjusted Metering Practice Implementation and Proposed Amendments to Section 503.17,* when submitting comments to the AESO.

The deadline for Stakeholders to provide comments is **August 11, 2023**. **Completed Stakeholder Comment Matrices are to be uploaded using the Stakeholder Feedback survey on AESO Engage**. The AESO will post all comments it receives on AESO Engage.

Related Materials

1. Blackline and clean copies of the draft proposed amended Section 503.17*;* and
2. *Stakeholder Comment Matrix – Proposed Adjusted Metering Practice Implementation and Proposed Amendments to Section 503.17* (note that this matrix also includes questions more broadly related to the AESO's AMP consultation).

Sincerely,

Tom Sloan

Legal Manager, ISO Tariff and Market Rules
Legal and Regulatory Affairs
rules_comments@aeso.ca

Stakeholder Comment Matrix for the following:

1. **Proposed Adjusted Metering Practice Implementation; and**
2. **Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17")**

Period of Comment:	July 21, 2023 through August 11, 2023	**Contact:**	Company Representative
Comments From:	Company Name	**Phone:**	Contact Phone Number
Date:	[yyyy/mm/dd]	**Email**:	

Instructions:

1. Please fill out the section above as indicated.
2. Please refer back to the "AESO Materials" section on AESO Engage.
3. Please respond to the questions below and provide your specific comments, if any. Blank boxes will be interpreted as favourable comments.

The AESO is seeking comments from Stakeholders on the implementation of the Adjusted Metering Practice regarding the following matters:

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	

The AESO is seeking responses from Stakeholders to the following questions on the development of proposed amendments to Section 503.17:

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	

Blackline – Proposed ISO Tariff Revisions | Adjusted Metering Practice

Rates

Rate DTS	Demand Transmission Service
Rate PSC	Primary Service Credit
Rate STS	Supply Transmission Service

Terms and Conditions

Section 3	System Access Service Requests
Section 5	Changes to System Access Service
Section 10	Settlement and Payment Terms

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Applicability

1 Rate DTS of the **ISO tariff**, *Demand Transmission Service*, applies to **system access service** provided at a **point of delivery** to:

(a) the **legal owner** of an **electric distribution system**;

(b) a **person** who has entered into an arrangement directly with the **ISO** for the provision of **system access service** under subsection 101(2) of the **Act**;

(c) the **legal owner** of an industrial system that has been designated as such by the **Commission**; or

(d) the City of Medicine Hat.

Rate

2 The **ISO** must determine the charge under Rate DTS in a **settlement period** in accordance with subsections 3 through 7 below as the sum of the connection charge, the **operating reserve** charge, the **transmission constraint rebalancing** charge, the voltage control charge and the other system support services charge.

Connection Charge

3(1) The **ISO** must determine the connection charge as the sum, over all rows, of the products calculated by multiplying the volume and charge in each row (a) through (i) of the following table.

Volume in **Settlement Period**	Charge
Bulk System Charge	
(a) Coincident **metered demand**	$10,840/MW/**month**
(b) **Metered energy**	$1.18/MWh
Regional System Charge	
(c) **Billing capacity**	$2,844.00/MW/**month**
(d) **Metered energy**	$0.90/MWh
Point of Delivery Charge	
(e) **Substation fraction**	$14,728.00/**month**
(f) First (7.5 × **substation fraction**) MW of **billing capacity**	$4,847.00/MW/**month**
(g) Next (9.5 × **substation fraction**) MW of **billing capacity**	$2,875.00/MW/**month**
(h) Next (23 × **substation fraction**) MW of **billing capacity**	$1,924.00/MW/**month**
(i) All remaining MW of **billing capacity**	$1,185.00/MW/**month**

3(2) The **ISO** must determine the coincident **metered demand** as the **metered demand** at the **point of delivery** averaged over the 15-minute interval in which the sum of the **metered demands** for all Rate DTS and Rate FTS of the **ISO tariff**, *Fort Nelson Demand Transmission Service*, **market participants** is greatest in the **settlement period**.

Operating Reserve Charge

4(1) The **ISO** must determine the **operating reserve** charge as the sum, over all hours in the **settlement period**, of the amount calculated in each hour as the product of:

(a) **metered energy** for the Rate DTS **market participant** in the hour; and

(b) the total cost of **operating reserves** in the hour divided by the total **metered energy** for all Rate DTS and Rate FTS **market participants** in the hour.

4(2) The **ISO** must estimate the **operating reserve** charge, if unable to determine it for a **settlement period** in accordance with subsection 4(1) above, as the sum, over all hours in the **settlement period**, of the amount calculated in each hour as the product of:

(a) **metered energy** for the Rate DTS **market participant** in the hour; and

(b) **pool price** in the hour multiplied by 5.18%.

Transmission Constraint Rebalancing Charge

5 The **ISO** must determine the **transmission constraint rebalancing** charge as the sum, over all hours in the **settlement period**, of the amount calculated in each hour as the product of:

(a) **metered energy** for the Rate DTS **market participant** in the hour; and

(b) the total cost of **transmission constraint rebalancing** payments in the hour divided by the total **metered energy** for all Rate DTS and Rate FTS **market participants** in the hour.

Voltage Control Charge

6 The **ISO** must determine the voltage control charge as the product of **metered energy** in the **settlement period** multiplied by $0.09/MWh.

Other System Support Services Charge

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

(a) the highest **metered demand** in the **settlement period** multiplied by $24.00/MW/**month**; and

(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**, unless the **ISO** waived the application of such a charge prior to December 31, 2016.

Terms

8(1) The **ISO** must apply Rate DTS separately at each **point of delivery**, except where Rate DTS applies to totalized **points of delivery** under ~~subsection~~subsections 10.3 or 10.4 of the **ISO tariff**, *Settlement and Payment Terms*.

8(2) The **ISO** must determine **metered energy** under Rate DTS, in an hour for which a Rate DOS of the **ISO tariff**, *Demand Opportunity Service,* transaction has been approved by the **ISO** at a **point of delivery** where Rate DOS applies, as the sum of:

(a) **metered energy** up to the Rate DTS **contract capacity**; plus

(b) any additional **metered energy** determined under subsection 2(2) of Rate DOS.

8(3) The **ISO** must apply Rider C of the **ISO tariff**, *Deferral Account Adjustment Rider*, to **system access service** provided under this rate.

8(4) The **ISO** must apply Rider F of the **ISO tariff**, *Balancing Pool Consumer Allocation Rider*, to **system access service** provided under this rate.

8(5) The terms and conditions of the **ISO tariff** form part of this rate.

Revision History

Effective	Description
202X-XX-XX	Updated as approved in **Commission** Decision …
2023-01-01	Updated charges as approved on a final basis in **Commission** Decision 27777-D01-2020 issued on December 21, 2022.
2022-01-01	Updated charges as approved on a final basis in **Commission** Decision 26980-D01-2021 issued on December 17, 2021.
2021-01-01	Updated charges as approved on a final basis in **Commission** Decision 26054-D01-2020 issued on December 18, 2020.
2020-04-01	Updated charges as approved on an interim refundable basis in **Commission** Decision 25175-D01-2020 issued February 28, 2020 and on a final basis approved in **Commission** Decision 25175-D02-2020.
2019-01-01	Updated charges, as approved in **Commission** Decision 24036-D01-2018 issued on December 18, 2018.
2018-01-01	Updated charges, as approved in **Commission** Decision 23065-D01-2017 issued on November 28, 2017.
2017-01-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 22093-D01-2016 issued on December 2, 2016 and on a final basis in **Commission** Decision 22093-D02-2017 on April 4, 2017.
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016.
2016-01-01	Updated charges, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015.
2015-11-26	Updated subsections and charges, as approved in **Commission** Decision 20623-D01-2015 issued on November 5, 2015.
2015-07-01	Updated subsections and charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015.
2013-10-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2013 and on a final basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

Applicability

1(1) Rate PSC of the **ISO tariff**, *Primary Service Credit*, applies to **system access service** provided at a **point of delivery** to a **market participant** who receives **system access service** under Rate DTS of the **ISO tariff**, *Demand Transmission Service*, and:

(a) does not utilize transformation facilities owned by a **legal owner** of **transmission facilities** to step transmission voltage down to 25 kV or less; or

(b) is served through an unconventional connection such as one using metering transformers.

1(2) Rate PSC does not apply to **system access service** to an isolated community as defined under the *Isolated Generating Units and Customer Choice Regulation*.

Rate

2(1) The **ISO** must determine the primary service credit to compensate a **market participant** whose connection does not include conventional transformation facilities owned by a **legal owner** of **transmission facilities**, including a connection for a **market participant** who has purchased, owns and operates its transformer.

2(2) The **ISO** must determine the primary service credit as the sum of the products calculated by multiplying the volume and credit in each row (a) through (e) of the following table.

Volume in **Settlement Period**	Credit
(a) **Substation fraction**	$11,635.00/**month**
(b) First (7.5 × **substation fraction**) MW of **billing capacity**	$3,829.00/MW/**month**
(c) Next (9.5 × **substation fraction**) MW of **billing capacity**	$2,271.00/MW/**month**
(d) Next (23 × **substation fraction**) MW of **billing capacity**	$1,520.00/MW/**month**
(e) All remaining MW of **billing capacity**	$1,185.00/MW/**month**

Terms

3(1) The **ISO** must apply Rate PSC separately at each **point of delivery**, except where Rate PSC applies to totalized **points of delivery** in accordance with ~~subsection~~subsections 10.3 or 10.4 of the **ISO tariff**, *Settlement and Payment Terms*.

3(2) The **ISO** must provide the primary service credit in conjunction with a reduced maximum local investment in accordance with subsection 4.7 of the **ISO tariff**, *Classification and Allocation of Connection Projects Costs*.

3(3) The **ISO** must apply Rider C of the **ISO tariff**, *Deferral Account Adjustment Rider*, to **system access service** provided under this rate.

3(4) The terms and conditions of the **ISO tariff** form part of this rate.

Revision History

Effective	Description
202X-XX-XX	Updated as approved in **Commission** Decision …
2023-01-01	Updated charges as approved in **Commission** Decision 27777-D01-2020 issued on December 21, 2022.
2022-01-01	Updated charges as approved on a final basis in **Commission** Decision 26980-D01-2021 issued on December 17, 2021.
2021-01-01	Updated charges as approved in **Commission** Decision 26054-D01-2020 issued on December 18, 2020.
2020-04-01	Updated charges as approved on an interim refundable basis in **Commission** Decision 25175-D01-2020 issued February 28, 2020 and revised Other System Support Services Charge waiver, as approved on a final basis in **Commission** Decision 25175-D02-2020 issued on November 30, 2020.
2019-01-01	Updated credit levels, as approved in **Commission** Decision 24036-D01-2018 issued on December 18, 2018.
2018-01-01	Updated credit levels, as approved in **Commission** Decision 23065-D01-2017 issued on November 28, 2017.
2017-01-01	Updated credit levels, as approved on an interim refundable basis in **Commission** Decision 22093-D01-2016 issued on December 2, 2016 and on a final basis in **Commission** Decision 22093-D02-2017 on April 4, 2017.
2016-04-01	Updated credit levels, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016.
2016-01-01	Updated credit levels, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015.
2015-07-01	Updated subsections and credit levels, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

Applicability

1(1) Rate STS applies to **system access service** provided at a **point of supply** to:

(a) a **legal owner** of a **generating unit** or an **aggregated generating facility** that is not subject to a **power purchase arrangement**;

(b) a holder of the **power purchase arrangement** for a **generating unit** that is subject to a **power purchase arrangement**;

(c) a **legal owner** of an industrial system that has been designated as such by the **Commission**;

(d) a **legal owner** of an **electric distribution system** where a **generating unit** or an **aggregated generating facility** is connected to the **electric distribution system**; or

(e) the City of Medicine Hat.

1(2) Rate STS does not apply to a **generating unit** constructed under the *Small Power Research and Development Act*, to the extent the volume of energy sales from such a **generating unit** is conducted under a contract specifically executed pursuant to the provisions of the *Small Power Research and Development Act*.

Rate

2(1) The **ISO** must determine the charge under Rate STS in a **settlement period** as the losses charge calculated as the sum, over all hours in the **settlement period**, of **metered energy** in the hour multiplied by **pool price** multiplied by a **loss factor** for the facility, where the **loss factor** is determined in accordance with section 501.10 of the **ISO rules**, *Transmission Loss Factors*, which is available to **market participants** on the AESO website.

2(2) The **ISO** must measure **metered energy** on a 15 minute interval for the purpose of calculating the losses charge under subsection 2(1) above.

Terms

3(1) The **ISO** must apply Rate STS separately at each **point of supply**, except where Rate STS applies to totalized **points of supply** under subsection 10.3 of the **ISO tariff**, *Settlement and Payment Terms*.

3(2) The **ISO** must apply Rider E, *Losses Calibration Factor Rider*, to **system access service** provided under this rate.

3(3) The **ISO** must apply Rider J, *Wind and Solar Forecasting Service Cost Recovery Rider*, to **system access service** provided under this rate for a wind and solar-powered **generating unit** or **aggregated generating facility**.

3(4) The terms and conditions of the **ISO tariff** form part of this rate.

Revision History

Effective	Description
202X-XX-XX	Updated as approved in **Commission** Decision …
2022-01-01	Updated charges as approved on a final basis in **Commission** Decision 26980-D01-2021 issued on December 17, 2021.
2021-01-01	Updated charges and removed the Regulated Gnenerating Unit Connection Cost section, as approved in **Commission** Decision 26054-D01-2020 issued on December 18, 2020.
2020-04-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 25175-D01-2020 issued February 28, 2020 and on a final basis in **Commission** Decision 25175-D02-2020 issued on November 30, 2020.
2019-01-01	Updated charges, as approved in **Commission** Decision 24036-D01-2018 issued on December 18, 2018.
2018-01-01	Updated charges, as approved in **Commission** Decision 23065-D01-2017 issued on November 28, 2017.
2017-01-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 22093-D01-2016 issued on December 2, 2016 and on a final basis in **Commission** Decision 22093-D02-2017 on April 4, 2017.
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016.
2016-01-01	Updated charges, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015.
2015-07-01	Updated subsections and charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015 except for the losses charge component in subsection 2(1) approved on an interim basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2013-10-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2014 and on a final basis, in **Commission** Decision 2014-242 issued on August 21, 2014 except for the losses charge component in subsection 2(1) approved on an interim basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

Applicability

3.1(1) This section applies to a **market participant** who has requested a new **system access service** or changes to an existing **system access service** under:

(a) Rate DTS, *Demand Transmission Service*;

(b) Rate FTS, *Fort Nelson Demand Transmission Service*;

(c) Rate PSC, *Primary Service Credit*; or

(d) Rate STS, *Supply Transmission Service*.

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

3.2(1) A **market participant** wishing to receive a new **system access service** or change an existing **system access service** must submit a request for **system access service** to the **ISO**, in the form specified by the **ISO** on the AESO website.

3.2(2) A **market participant** must provide the following critical information, as part of its request under subsection 3.2(1) above:

(a) the requested Rate STS **contract capacity** or requested change in Rate STS **contract capacity**, including **contract capacity** by stage, if applicable;

(b) the **maximum capability** of each **generating unit** or **aggregated generating facility**;

(c) the requested Rate DTS **contract capacity** or requested change in Rate DTS **contract capacity**, including **contract capacity** by stage, if applicable;

(d) generation type(s) in the case of a **generating unit** or **aggregated generating facility**;

(e) in-service date, including the dates relating to any staged **contract capacity** request;

(f) location of the load or generation related to the request of the **market participant**; and

(g) if load or generation related to the request of the **market participant** are or will be part of a **Commission**-designated industrial system, or if the **market participant** has otherwise obtained an approval from the **Commission** that permits the export to the **interconnected electric system** of electric energy in excess of the **market participant**'s own self-supply requirements, whether the load and generation will be metered on a gross or net basis.

3.2(3) In addition to the critical information set out in subsection 3.2(2) above, the **ISO** may establish additional critical information as part of the **ISO**'s connection process and a **market participant** must provide any additional critical information that exists at the time the **market participant** makes a **system access service** request.

3.2(4) If a **market participant** requesting **system access service** is the **legal owner** of an **electric distribution system** and its **system access service** request contemplates a load transfer from one **point of delivery** to another **point of delivery**, or is related to another **system access service**, then the **market participant** must include the following additional critical information as part of its **system access service** request:

(a) a list of the related **system access service** request(s);

(b) the amount of any load transfer from one **point of delivery** to another **point of delivery**;

(c) all distribution and transmission connection alternatives, or combinations of both, that have been considered by the **legal owner** of the **electric distribution system**;

(d) the larger geographical area considered, including any **point of delivery** or **point of supply** in the area;

(e) a complete description of why the **system access service** request is necessary; and

(f) any other information that the **ISO** determines to be relevant.

Review of System Access Service Request

3.3(1) The **ISO** may, at any point in the **ISO**'s connection process, reject a **system access service** request submitted to the **ISO** under subsection 3.2 above if the **ISO** determines the request to be incomplete.

3.3(2) If the **ISO** determines a **system access service** request under subsection 3.2 above to be complete, then the **ISO** must determine whether a new or amended **needs approval** is required to respond to the request.

3.3(3) If a new or amended **needs approval** is required under subsection 3.3(2) above, then the **market participant** must follow the connection process described on the AESO's website and pay a **construction contribution** in accordance with section 4 of the **ISO tariff**, *Classification and Allocation of Connection Projects Costs.*

3.3(4) If a new or amended **needs approval** is not required under subsection 3.3(2) above, then the **market participant** must follow the **ISO**'s behind the fence or contract change process. The **ISO** must prepare if applicable, an amendment to the **market participant**'s *System Access Service Agreement* substantially in the form included in Appendix A of the **ISO tariff**, *System Access Service Agreement Proformas*, and may require payment of a **construction contribution** in accordance with section 4 of the **ISO tariff**, *Classification and Allocation of Connection Project Costs*, or an adjustment to the **construction contribution** in accordance with section 5 of the **ISO tariff**, *Changes to System Access Service*.

ISO Preferred Alternative

3.4(1) If a new or amended **needs approval** is required for a connection project, the **ISO** must determine how to respond to the **system access service** request, and select the **ISO**'s preferred connection alternative taking into account relevant factors including the following:

(a) the overall long-term cost of a connection alternative, including, as applicable:

(i) if the **system access service** request was submitted by the **legal owner** of an **electric distribution system**, all distribution costs;

(ii) costs classified as participant-related in accordance with subsection 4.2(2) of the **ISO tariff**, *Classification and Allocation of Connection Projects Costs*;

(iii) costs associated with **system transmission facilities**; and

(iv) all other transmission costs (including the costs of any non-wires solutions) not included in subsections 3.4(1)(a)(i), (ii) and (iii) above required for the connection; and

(b) if the **system access service** request is for both Rate DTS and Rate STS, the **ISO** must consider the effect on the **transmission system** separately for Rate DTS and Rate STS.

3.4(2) For a **system access service** request for Rate DTS, if the **ISO**'s preferred connection alternative includes or depends upon the construction of **system transmission facilities**, then the **market participant** must:

(a) accept the preferred connection alternative and pay any applicable advancement costs determined by the **ISO** in accordance with subsection 4.2(3)(a) of section 4 of the **ISO tariff**, *Classification and Allocation of Connection Projects Costs*;

(b) amend the **market participant**'s **system access service** request to connect at a reduced **contract capacity** that:

(i) can be accommodated by the existing **transmission system**; and

(ii) as determined by the **ISO**, allows for a minimum of 5 years of area growth following the **market participant**'s projected in-service date, or such other reduced **contract capacity** or period of time that the **ISO** determines to be consistent with the **ISO**'s **transmission system** planning obligations and the safe, reliable and economic operation of the **interconnected electric system**;

(c) amend the **market participant**'s **system access service** request to connect at an in-service date that is a minimum of 5 years following the execution of an agreement for **system access service** for Rate DTS substantially in the form included in Appendix A of the **ISO tariff**, *System Access Service Agreement Proformas*; or

(d) withdraw the **system access service** request.

3.4(3) For a **system access service** request for Rate STS, if the **ISO**'s preferred connection alternative includes or depends upon the construction of **system transmission facilities**, then the **market participant** must:

(a) accept the **ISO**'s preferred connection alternative;

(b) amend the **market participant**'s **system access service** request to connect at a reduced **contract capacity** that the **ISO** determines to be consistent with the **ISO**'s **transmission system** planning obligations and the safe, reliable and economic operation of the **interconnected electric system**; or

(c) withdraw the **system access service** request.

Construction Commitment Agreement

3.5(1) The **market participant** providing **financial security**, **construction contribution** or both for a connection project must enter into a *Construction Commitment Agreement* with the **legal owner** of the **transmission facility**, substantially in the form included in Appendix A of the **ISO tariff**, *System Access Service Agreement Proformas*, 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**.

Execution of Agreement for System Access Service

3.6(1) A **market participant** must execute a *System Access Service Agreement* for Rate DTS or for Rate STS substantially in the form included in Appendix A of the **ISO tariff**, *System Access Service Agreement Proformas*:

(a) if a new or amended **needs approval** is required for a connection project, before the **ISO** submits a **needs identification document** to the **Commission** or, before the **ISO** approves the connection project under the abbreviated needs approval process provided for under the *Transmission Regulation*; or

(b) if a new or amended **needs approval** is not required for a connection project, at the time specified by the **ISO** on the AESO website.

3.6(2) A **market participant** must execute a *System Access Service Agreement* for Rate DTS for a **contract capacity** that, in the **ISO's** determination, approximates the expected maximum coincident sum of the flows from the **transmission system** through each physical connection to the **market participant's** facilities.

3.6(3) A **market participant** must execute a *System Access Service Agreement* for Rate STS for a **contract capacity** that, in the **ISO**'s determination, approximates the expected maximum coincident sum of the flows to the **transmission system** through each physical connection from the **market participant's** facilities**.**

~~3.6(4~~3.6(4) Notwithstanding subsections 3.6(2) and 3.6(3) above, a **market participant** may execute a *System Access Service Agreement* for Rate DTS or Rate STS at a **contract capacity** determined by the **market participant** on either a gross or net basis if the **market participant** is seeking to connect a **Commission**-designated industrial system to the **transmission system**, or if an approval from the **Commission** has been obtained to permit the export of electric energy in excess of the **market participant's** own self-supply requirements (or in excess of a transmission-connected end-use customer's own self-supply requirements, if an arrangement under section 101(2) of the Act has not been entered into).

3.6(5) Notwithstanding subsections 3.6(2) and 3.6(3) above, if a **market participant** is the **legal owner** of an **electric distribution system** and each feeder at the substation does not have a **revenue meter** or the infrastructure to accommodate the installation of a **revenue meter**, as determined by the **ISO**, then the **market participant** may:

(a) execute a *System Access Service Agreement* for Rate DTS for a **contract capacity** that, in the **ISO**'s determination, reflects the maximum coincident sum of the flows from the **transmission system** using the available **revenue meters** and infrastructure at the substation; and

(b) execute a *System Access Service Agreement* for Rate STS for a **contract capacity** that, in the **ISO**'s determination, reflects the maximum coincident sum of the flows to the **transmission system** using the available **revenue meters** and infrastructure at the substation.

3.6(~~5~~6) Prior to executing a *System Access Service Agreement* for Rate DTS or Rate STS for a connection project that requires a new or amended **needs approval** , a **market participant** must inform the **ISO** of any regulatory approvals and non-financial matters that the **market participant** expects could cause a delay or prevent the achievement of the in-service date that has been requested by the **market participant**, together with the expected dates for the receipt of the regulatory approvals and successful resolution of the non-financial matters.

3.6(~~5~~7) The **ISO** must include as a condition precedent in Section 2 of the *System Access Service Agreement*, the receipt of any regulatory approvals identified by the **market participant** pursuant to subsection 3.6(~~4~~6) above that the **ISO** determines could cause a delay or prevent the achievement of the in-service date that has been requested by the **market participant**.

3.6(~~6~~8) The **ISO** may, in its discretion, include as a condition precedent in Section 2 of the *System Access Service Agreement*, the successful resolution of any non-financial matters identified by the **market participant** pursuant to subsection 3.6(~~4~~6) above.

3.6(~~7~~9) The **ISO** may reject a system access service request if a **market participant** does not execute a *System Access Service Agreement* for Rate DTS or Rate STS by the time specified by the AESO pursuant to subsection 3.6(1) above.

Effective Date of Agreement for System Access Service

3.7(1) If a new or amended **needs approval** is required for a connection project, a *System Access Service Agreement* for Rate DTS or Rate STS becomes effective immediately following the later of:

(a) the issuance by the **Commission** of the permit(s) and licence(s) for the connection project;

(b) the receipt by the **market participant** of any regulatory approvals included as a condition precedent in Section 2 of the *System Access Service Agreement*; and

(c) the successful resolution of any non-financial matters included as a condition precedent in Section 2 of the *System Access Service Agreement*.

3.7(2) Until such time as conditions precedent related to any regulatory approvals or non-financial matters included in Section 2 of a *System Access Service Agreement* have been satisfied, the **market participant** must provide the **ISO** with quarterly updates or as otherwise specified by the **ISO** regarding the status of the regulatory approvals or non-financial matters, including updates to the expected dates for the receipt of any regulatory approvals and the successful resolution of non-financial matters.

3.7(3) A **market participant** must promptly inform the **ISO** when any regulatory approvals that are the subject of conditions precedent have been received or non-financial matters that are the subject of conditions precedent have been successfully resolved.

3.7(4) If a new or amended **needs approval** is not required for a connection project, a *System Access Service Agreement* for Rate DTS or Rate STS becomes effective the day it is executed.

3.7(5) If a new or amended **needs approval** is required for a connection project, the **ISO** may cancel a **system access service** request and terminate the related *System Access Service Agreement* for Rate DTS or Rate STS if the *System Access Service Agreement* for Rate DTS or Rate STS does not become effective within 1 year of issuance by the **Commission** of the permit(s) and licence(s).

3.7(6) The **ISO** must include a connection project in the **ISO**'s forecast, **transmission system** plans and engineering connection assessments when the related *System Access Service Agreement* for Rate DTS or Rate STS becomes effective in accordance with subsection 3.7(1) or (4) above.

Amending a System Access Service Request

3.9(1) A **market participant** must, in a timely manner, notify the **ISO** of any changes to the information provided in a **system access service** request if the information provided in, or in connection with, a **system access service** request ceases to be accurate.~~.~~

3.9(2) If a **market participant** changes the information provided in a **system access service** request, the **ISO** may:

(a) accept the change, subject to such further information or requirements that the **ISO** determines to be necessary that may include:

(i) revised or new connection studies; and

(ii) revised or new connection alternatives;

or

(b) reject the change.

3.9(3) The **ISO** may, at any point in the **ISO**'s connection process, cancel a **system access service** request if a **market participant** fails to notify the **ISO** of a change to the critical information required under subsections 3.2(2), 3.2(3) and 3.2(4) above in a timely manner.

3.9(4) A **market participant** may reapply for **system access service** under subsection 3.2(1) above, if the **ISO** rejects or cancels the **system access service** request.

Cancellation Due to Action or Inaction

3.10 The **ISO** may cancel a connection project after reasonably concluding, based on the action or inaction of the **market participant**, that the **market participant** is not proceeding with the market participant's **system access service request**.

Alternative Processes

3.11 The **ISO** may satisfy the provisions of this section through processes other than those described above and, in particular, alternative processes may be utilized if the **ISO** anticipates the impact on the **transmission system** may be significant.

Revision History

Effective	Description
202X-XX-XX	Updated as approved in **Commission** Decision …
2023-07-20	Revised as applied for in the AESO 2022 ISO Tariff Modernization Application, as approved in **Commission** Decision 27864-D01-2023 issued on May 31, 2023 and in effect as of July 20, 2023 as per **Commission** Decision 28294-D01-2023 (Alberta Electric System Operator ISO Tariff Compliance Filing Pursuant to Decision 27864-D01-2023).
2021-01-01	Revised and reformatted all subsections, as approved in **Commission** Decision 25175-D02-2020 issued on November 30, 2020.
2015-07-01	Updated subsections, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015.

Applicability

5.1 This section applies to a **market participant** who has requested or is receiving **system access service** under:

(a) Rate DTS, *Demand Transmission Service*;

(b) Rate PSC, *Primary Service Credit*; or

(c) Rate STS, *Supply Transmission Service*.

Events Resulting in Adjustments to Construction Contributions and Contract Capacity

5.2(1) A **market participant**, the **ISO** or the **legal owner** of a **transmission facility** may initiate a review of the **construction contribution** that the **ISO** had previously determined for a connection project.

5.2(2) If the **ISO** determines that the contract capacity amount in a *System Access Service Agreement* for Rate DTS or Rate STS previously determined by the **ISO** in respect of subsections 3.6(2), (3), (4) and (~~3)~~ of the **ISO tariff**, *System Access Service Request,* does not reflect the actual flows, the **ISO** may adjust the contract capacity to reflect such actual flows and the **market participant** must pay any recalculated amounts for any **construction contribution** in accordance with this section 5 of the **ISO tariff**, *Changes to System Access Service*, and any contribution for a **generating unit** or **aggregated generating facility** calculated in accordance with section 7 of the **ISO tariff**, *Generating Unit Owner's Contribution*, as applicable, provided that:

(a) prior to determining whether to adjust any contract capacity amount, the **ISO** must discuss the potential adjustment with the **market participant**; and

(b) the **ISO** must not adjust contract capacity unless the deviation from actual flows is 10 per cent or greater than the contract capacity amount.

5.2(3) A **market participant** may dispute a decision made by the **ISO** under subsection 5.2(2) in accordance with Section 103.2 of the ISO rules, *Dispute Resolution*.

5.2(4) The **ISO** must review a **construction contribution** determination and may determine a **construction contribution** adjustment is required when:

(a) a **market participant** materially increases or decreases **contract capacity** or investment term or terminates **system access service**, prior to the expiry of the investment term for a connection project;

(b) one or more additional **market participants** use facilities originally installed for an existing **market participant**, resulting in sharing of facilities as provided for in subsection 5.5 below;

(c) connection project costs previously classified as system-related are reclassified as participant-related to meet changes in **market participant** requirements;

(d) connection project costs previously classified as participant-related are reclassified as system-related;

(e) a material error in the original **construction contribution** is identified; or

(f) the estimated or actual cost of the connection project materially varies from the original estimate.

5.2(5) The **ISO** must determine a **construction contribution** under the provisions of section 4 of the **ISO tariff**, *Classification and Allocation of Connection Projects Costs*, rather than this section 5, if an increase in **contract capacity** requires the construction of **transmission facilities** at an existing **point of delivery** or **point of supply**.

5.2(6) The **ISO** must not make an adjustment to a **construction contribution** more than 20 years after **commercial operation** of a connection project.

Reductions or Terminations of Contract Capacity

5.3(1) The **ISO** must make a reduction or termination of **contract capacity** effective 5 years after the date of notice of the request for reduction or termination, subject to subsection 5.3(2) below.

5.3(2) A **market participant** may make a lump sum payment determined by the **ISO** in lieu of all or a portion of the 5-year notice period in subsection 5.3(1) above.

5.3(3) The **ISO** must calculate the payment in lieu of notice (also known as a "PILON") as a share of the costs of **system transmission facilities** incurred to reasonably accommodate a **market participant**'s **contract capacity** over the 5-year planning horizon of the **transmission system**, and must calculate the payment for a **market participant** reducing, terminating or changing the start date or end date for **contract capacity** under Rate DTS, after executing a *System Access Service Agreement*, as the present value of the difference in bulk system and regional system charges that would be attributed to the service:

(a) with the reduction or termination of or change of date for **contract capacity** during the notice period; and

(b) with the contract capacity or start date or end date for contract capacity indicated in the System Access Service Agreement last executed by the **market participant**.

5.3(4) The **ISO** must use the discount rate provided in subsection 4.9 of the **ISO tariff**, *Classification and Allocation for Connection Projects Costs*, in the present value calculation in subsection 5.3(3)(a) and (b) above.

5.3(5) A **market participant** may make a payment in lieu of notice at any time prior to or during the 5 year notice period, for the remainder of the notice period and the **ISO** must receive such payment at least 30 **days** before the reduction or termination of **contract capacity**.

5.3(6) The **ISO** may waive or reduce the requirement for payment in lieu of notice if, as determined by the **ISO**:

(a) **contract capacity** is transferred to a **system access service** of the same **market participant** at a nearby transmission substation;

(b) **transmission system** benefits arise from the reduction or termination of **contract capacity**, which may include relief of regional transmission constraints, removal of capacity limitations which would restrict **system access service** to other **market participants** or avoidance of future upgrades to the **transmission system**; or

(c) during the 5 years prior to the reduction in **contract capacity** becoming effective, the **market participant** has not increased **contract capacity** at the **point of delivery** at which the reduction in **contract capacity** occurs and, at the time that the **market participant** requests to reduce or terminate the **contract capacity**, has not executed a *System Access Agreement* under Rate DTS for future increases in **contract capacity** at the **point of delivery**.

5.3(7) The **ISO** may, at any time during the remainder of a notice period for which a payment in lieu of notice was made:

(a) re-assess the payment in lieu of notice if material differences arise between the requested and actual **contract capacities** or between expected and actual load; and

(b) require additional payment from the **market participant**.

Metered Demand Above Pre-Notice Contract Capacity

5.4(1) The **ISO** must determine the **contract capacity** immediately following the 5-year notice period required by subsection 5.3(1) above to be the maximum of:

(a) the pre-notice **contract capacity** less the reduction of **contract capacity** the **market participant** requested; or

(b) the highest **metered demand** during the 5-year notice period less the reduction of **contract capacity** the **market participant** requested.

5.4(2) A **market participant** may provide an additional notice of reduction to request a subsequent reduction of **contract capacity** to the original notice level, if the highest **metered demand** affects the maximum determined under subsection 5.4(1) above.

Shared Facilities

5.5(1) The **ISO** must allocate the participant-related costs of shared **transmission facilities** to **market participants** if **transmission facilities** are constructed to serve a **market participant** and then used to serve other but not all **market participants** within 20 years after **commercial operation** of the original connection project.

5.5(2) The **ISO** must allocate the participant-related costs of shared **transmission facilities**:

(a) when a transmission line is shared by two or more substations, by allocating the costs of the shared line to those substations in accordance with subsection 5.5(3) below; and

(b) when a single substation is shared by 2 or more **market participants**, by allocating the shared costs associated with the substation to those **market participants** in accordance with subsection 5.5(4) below.

5.5(3) The **ISO** must allocate the participant-related costs of a transmission line shared by 2 or more substations by:

(a) determining the higher of the sum of all Rate DTS **contract capacities** or the sum of all Rate STS **contract capacities** for each substation in each of the 20 years following **commercial operation** of the original transmission line, and assigning a **contract capacity** of zero in a year in which a substation did not exist;

(b) calculating the percentage share of the transmission line attributable to each substation by dividing the **contract capacity** determined in subsection 5.5(3)(a) above for the substation in a year by the sum of **contract capacities** determined for all sharing substations in that year;

(c) calculating the average percentage share over the full 20-year period for each substation; and

(d) multiplying the cost of the shared transmission line by the average percentage share determined for each substation.

5.5(4) The **ISO** must allocate the participant-related costs of **transmission facilities** used to provide **system access services** to more than one **market participant** at a single substation to the **market participants** at the substation by:

(a) determining the **substation fraction** for each **market participant** in each of the 20 years following **commercial operation** of the original connection project, assigning a **contract capacity** of zero in any year in which a **market participant** did not receive **system access service**;

(b) calculating the average **substation fraction** over the full 20-year period for each **market participant**; and

(c) multiplying the cost of the shared **transmission facilities** by the average **substation fraction** determined for each **market participant**.

5.5(5) The **ISO**, as a result of the allocation of costs of shared **transmission facilities** under subsections 5.5(2), (3) and (4) above:

(a) must reduce the participant-related costs allocated to the original **market participant**; and

(b) may refund under subsection 5.6 below, where applicable, in part or in full, a **construction contribution** previously paid by that **market participant**.

5.5(6) The **ISO**, as a result of the allocation of costs of shared **transmission facilities** under subsections 5.5(2), (3) and (4) above:

(a) must include the allocated share of existing **transmission facilities** in the determination of participant-related costs for the additional **market participants** under subsection 4.2(2)(d) of the **ISO tariff**, *Classification and Allocation for Connection Projects Costs*; and

(b) may assess **construction contributions** to the additional **market participants** under section 4 of the **ISO tariff**, *Classification and Allocation for Connection Projects Costs*.

5.5(7) The **ISO** must reclassify the participant-related costs of a connection project as system-related costs if, within 20 years after **commercial operation** of the original connection project, **transmission facilities** are constructed to serve a **market participant** and are then, in the determination of the **ISO**, used for the benefit of many **market participants,** based on calculating the average percentage share over the full 20 year period for the original connection project and the time the **ISO** reclassified the costs as system-related.

Determination of Construction Contribution

5.6 The **ISO** must determine the amount of an adjustment to a **construction contribution** paid for a connection project in accordance with the **construction contribution** provisions described in the **ISO tariff** as applied to the **transmission facility** at the time construction is completed.

Payments and Refunds

5.7(1) A **market participant** must pay a **construction contribution** adjustmentwithin 30 **days** of a request for payment.

5.7(2) A **legal owner** of a **transmission facility** must refund a **construction contribution** adjustment:

(a) within 30 **days** after the effective date of a change to a *System Access Service Agreement*, if the refund arises from changes to **contract capacity** or investment term that do not require construction of a **transmission facility**;

(b) within 90 **days** after the **Commission** issues permit and licence for a **transmission facility**, if the refund results from the construction of the **transmission facility**; and

(c) within 90 **days** of the **ISO** determining the amount of the adjustment, in all other circumstances.

5.7(3) The **market participant** must pay:

(a) an increase in **construction contribution** by way of electronic funds transfer or wire transfer to the bank account a **legal owner** of a **transmission facility** specifies; and

(b) a payment in lieu of notice by way of electronic funds transfer or wire transfer to a bank account the **ISO** specifies.

5.7(4) A **market participant** must pay and a **legal owner** of a **transmission facility** must refund all adjustments without interest.

5.7(5) A **market participant** is not required to pay and a **legal owner** of a **transmission facility** is not required to refund an adjustment amount less than $10 000.

Revision History

Effective	Description
202X-XX-XX	Updated as approved in **Commission** Decision …
2023-07-20	Revised as applied for in the AESO 2022 ISO Tariff Modernization Application, as approved in **Commission** Decision 27864-D01-2023 issued on May 31, 2023 and in effect as of July 20, 2023 as per **Commission** Decision 28294-D01-2023 (Alberta Electric System Operator ISO Tariff Compliance Filing Pursuant to Decision 27864-D01-2023).
2021-01-01	Updated to remove the subsection relating to Regulated Generating Unit Connection Costs, as approved in **Commission** Decision 26054-D01-2020 issued on December 18, 2020.
2021-01-01	Updated $0.00/MWh charge, as approved in **Commission** Decision 25175-D01-2020 issued on November 30, 2020.
2015-07-01	Updated subsections, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015.

Applicability

10.1 This section applies to a **market participant** who has requested or is receiving **system access service** under any rate of the **ISO tariff**.

Billing Procedures

10.2(1) The **ISO** must issue a statement of account for **system access service** no later than 15 **business days** after the end of each **settlement period**, which statement may include:

(a) amounts determined on an initial basis for that **settlement period**;

(b) amounts determined on an interim basis for the period 2 **months** prior to that **settlement period**; and

(c) amounts determined on a final basis for the period 4 **months** prior to that **settlement period**.

10.2(2) The **ISO** may review a statement of account and may issue a new statement of account based on the results of that review.

10.2(3) The **ISO** may choose not to issue a statement of account on an interim or final basis if it would result in a charge or refund of less than $1,000.

10.2(4) The **ISO** may use estimated values to produce a statement of account if:

(a) **metered demand** or **metered energy** data is not available or is incomplete;

(b) **metering equipment** fails or the data is under dispute; or

(c) the **ISO**'s billing and settlement system is unable to produce a statement of account.

10.2(5) The **ISO** must, when a statement of account is based on estimated values, make an adjustment, to reflect the use of actual or more appropriate estimated values in a subsequent statement of account issued in accordance with:

(a) amounts determined on an interim basis for the period 2 **months** prior to that settlement period; or

(b) amounts determined on a final basis for the period 4 **months** prior to that settlement period.

10.2(6) The **ISO** may deduct from a statement of account any amounts it owes to the **market participant** or its **affiliates**.

Totalized Billing at Separate Substations

10.3(1) The **ISO** may totalize multiple **points of delivery**, **points of supply**, or both, at separate substations, for a single **market participant** and produce 1 statement of account for the **market participant** that is an industrial complex or the **legal owner** of an **electric distribution system** that is obtaining **system access service** on behalf of a **market participant** that is an industrial complex.

10.3(2) The **ISO** must base its decision to totalize under subsection 10.3(1) on a review of:

(a) the economics of providing more than a single substation;

(b) re-classification of the site as a **Commission**-designated industrial system; or

(c) the existence of a credible transmission bypass alternative.

Totalized Billing and Contracting at the Same Substation

10.4(1) For the purposes of billing and contracting under the **ISO tariff**, the **ISO** may totalize multiple **points of delivery** at a single substation under Rate DTS, *Demand Transmission Service*.

10.4(2) For the purposes of billing and contracting under the **ISO tariff**, the **ISO** may totalize multiple **points of supply** at a single substation under Rate STS, *Supply Transmission Service*.

Adjustments

10.~~4~~5(1) A **market participant** may request that a statement of account be recalculated and reissued 45 or more **days** after an amount has been determined on a final basis for a **settlement period**, as a result of:

(a) unavailable or incomplete **meter** data;

(b) inaccurate estimates of **meter** data; or

(c) reconciliation with updated estimates of **meter** data;

10.~~4~~5(2) The **ISO** may recover the cost of recalculating and reissuing a statement of account from the **market participant**.

Provision of Settlement Data

10.~~5~~6(1) The **ISO** must make available to a **market participant** upon request data required to verify a statement of account for **system access service**.

10.~~5~~6(2) The **ISO** may recover the cost of retrieval and provision of data required to verify a statement of account for **system access service** from the **market participant**.

Payment Terms

10.~~6~~7(1) A **market participant** must pay the amounts shown on the statement of account no later than 20 **business days** after the end of the **settlement period**.

10.~~6~~7(2) The **market participant** must make payment by way of electronic funds transfer or wire transfer to a bank account specified by the **ISO**.

Effect of Non-Compliance

10.~~7~~8(1) The **ISO** may charge interest and other amounts, suspend or terminate **system access service** and take other action in accordance with section 103.7 of the **ISO rules**, *Financial Default and Remedies*, if a **market participant**:

(a) fails to comply with a requirement to provide **financial security** to the **ISO** for **system access service**; or

(b) fails to pay in full a **financial obligation** to the **ISO** for **system access service**, on or before a specified due date for that **financial obligation**.

10.~~7~~8(2) The **ISO** must not reinstate **system access service** to a **market participant** unless the **market participant** has paid all **financial obligations** owing to the **ISO** in full and has restored or secured its credit facility in a manner satisfactory to the **ISO**.

Revision History

Effective	Description
202X-XX-XX	Updated as approved in **Commission** Decision …
2021-01-01	Revised and reformatted all subsections, as approved in **Commission** Decision 25175-D02-2020 issued on November 30, 2020.
2015-07-01	Updated subsections, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

Applicability

1 Section 503.17 applies to:

(a) the **legal owner** of a **revenue meter**; and

(b) the **ISO**.

Requirements

Revenue Metering System

2(1) The **legal owner** of a **revenue meter** must install and operate a **revenue metering system** that allows for financial settlement as required by the **ISO rules** and **ISO tariff**.

Substations that Connect to an Electric Distribution System

3(1) The **legal owner** of a **revenue meter** must install, at a minimum, all measurement transformers, associated wiring, and rack space required for a **revenue metering system** at each switchgear in a switchgear lineup if:

(a) the switchgear lineup connects a **transmission facility** to an **electric distribution system**; and

(b) the complete switchgear lineup is installed after <effective date>.

Measurement Point Definition Record

~~2~~4(1) The **legal owner** of a **revenue meter** must, where such **legal owner** requires a new **measurement point definition record** or an amendment to an existing **measurement point definition record**, submit a complete application form to the **ISO** prior to energizing the new or altered **revenue metering system**.

(2) The **ISO** must issue a **measurement point definition record** for a **measurement point** to the **legal owner** of the **revenue meter**, or to a **person** designated by the **legal owner** of the **revenue meter**, if the information in the application form submitted in accordance with subsection 2(1):

(a) is complete;

(b) allows for the proper measurement of **metered energy**, measurement of **metered demand**, and calculation of **apparent power** ~~in accordance with~~as required by the **ISO rules** and ~~the~~ **ISO tariff**~~, as applicable~~; and

(c) avoids a metering configuration that results in a deductive totalizing calculation for the **measurement point**.

~~**(3)** The **legal owner** of a **revenue meter** must install and operate a **revenue meter** in accordance with the **measurement point definition record** the **ISO** issues in accordance with subsection 2(2).~~

Revenue Meter

~~3~~5(1) The **legal owner** of a **revenue meter** must ensure that the **revenue meter** has an accuracy class rating that is less than or equal to 0.2% for Watthour measurement if:

(a) the capacity of the **metering point** of the **revenue meter** is greater than or equal to 1.0 MVA; and

(b) the **revenue meter** is not the subject of a dispensation under the *Electricity and Gas Inspection Act*, RSC 1985 c E-4, as amended.

(2) The **legal owner** of a **revenue meter** must ensure that the **revenue meter** has an accuracy class rating that is less than or equal to 0.5% for Varhour measurement if:

(a) the capacity of the **metering point** of the **revenue meter** is greater than or equal to 1.0 MVA; and

(b) the **revenue meter** is not the subject of a dispensation under the *Electricity and Gas Inspection Act*, RSC 1985 c E-4, as amended.

Measurement Transformer

~~4~~6(1) The **legal owner** of a **revenue meter** must ensure that the measurement transformer has an accuracy class rating less than or equal to 0.3% if:

(a) the capacity of the **metering point** of the **revenue meter** is greater than or equal to 1.0 MVA; and

(b) the measurement transformer is not the subject of a dispensation under the *Electricity and Gas Inspection Act*, RSC 1985 c E-4, as amended.

(2) The **legal owner** of a **revenue meter** must, unless the **ISO** approves otherwise, ensure that the measurement transformer:

(a) is located and connected without compensation methods;

(b) produces a real **metering point**; and

(c) has a dedicated current transformer core for measurement.

Metering Data

~~5~~7(1) The **legal owner** of a **revenue meter** must retain metering data from the **revenue metering system**, including a record of final estimates and adjustments and the method used to perform the estimates or adjustments, for a period of at least 8 years.

(2) The **legal owner** of a **revenue meter** must process metering data for each **measurement point** in accordance with the algorithm in the **measurement point definition record** issued in accordance with subsection 2(2).

(3) The **legal owner** of a **revenue meter** must, within 30 **days** of energizing the **revenue meter** for the first time, validate the **metering equipment** and the metering data.

(4) The **legal owner** must maintain validation records until the date of the next in-situ test.

Revenue Meter Testing and Reporting

~~6~~8(1) The **legal owner** of a **revenue meter** must perform in-situ testing:

(a) upon a change of any **metering equipment** associated with the **revenue meter**; and

(b) as per the testing intervals set out in Table 1:

Table 1 – In-situ Testing Frequency Based on Revenue Meter MW Class

MW Class	Testing Interval
(i) Greater than 20 MW	(A) Every 2 years from the date of commissioning; or (B) For existing revenue meters, every 2 years from the date of the previous in-situ test.
(ii) Greater than or equal to 5 MW and less than or equal to 20 MW	(A) Every 4 years from the date of commissioning; or (B) For existing revenue meters, every 4 years from the date of the previous in-situ test.

(2) The **legal owner** of a **revenue meter** must calculate the MW class in subsection 6(1)(b) as follows:

(a) determine the total active energy in MWh at the **measurement point** for the calendar year; and

(b) divide the total active energy determined in subsection 6(2)(a) by the number of settlement intervals in the same calendar year, including the intervals in which active energy is zero.

(3) The **legal owner** of a **revenue meter** must provide the results of the in-situ test performed in subsection 6(1) to the **ISO** if the test resulted in an error measurement of +/- 3%.

(4) Notwithstanding subsections 6(1), 6(2) and 6(3) above, the **legal owner** of a **revenue meter** must, at the request of the **ISO**, complete and report the results of an in-situ test for the **metering equipment** within 30 **days** of receiving the **ISO**'s request or within a mutually agreed time frame.

Measurement Data Corrections

~~7~~9 The **legal owner** of a **revenue meter** must, if the **legal owner** discovers an error in measurement data, where the net difference in consumption from the measurement data previously submitted to the **ISO** is:

(a) 100 MWh or greater, for sites other than large micro-generation; or

(b) 100 kWh or greater for large micro-generation sites,

notify the **ISO** in writing of the reason for the error.

Restoration

~~8~~10**(1)** The **legal owner** of a **revenue meter** must, upon becoming aware of a failure of the **revenue metering system**, restore the **revenue metering system** within 30 **days**.

(2) The **legal owner** of a **revenue meter** must notify the **ISO** in writing of the failure if the **legal owner** is unable to restore the **revenue metering system** within 30 **days** in accordance with subsection 8(1).

(3) The **legal owner** of a **revenue meter** must include a plan to restore the **revenue metering system** when notifying the **ISO** in accordance with subsection 8(2).

(4) The **legal owner** of a **revenue meter** must notify the **ISO** in writing after completing the restoration of the **revenue metering system** in accordance with the plan referred to in subsection 8(3).

Revision History

Date	Description
202X-XX-XX	Included new subsection 2 to require legal owners of revenue meters to install revenue metering that will allow for appropriate financial settlement. Included new subsection 3 to require infrastructure required for feeder metering to be installed at substations that connect to electric distribution systems to implement the adjusted metering practice. Removed installation requirement under subsection 4 as redundant to new subsection 2.
2024-04-01	Amended, as approved in **Commission** Decision 28176-D01-2023 issued on June 13, 2023. See *Table of Concordance for the Transition from Division 502 to Division 503* on www.aeso.ca for further information regarding the change from Division 502 – Technical Requirements to Division 503 – Technical and Operating Requirements.
2021-03-18	Initial release.

Applicability

1 Section 503.17 applies to:

(a) the **legal owner** of a **revenue meter**; and

(b) the **ISO**.

Requirements

Revenue Metering System

2(1) The **legal owner** of a **revenue meter** must install and operate a **revenue metering system** that allows for financial settlement as required by the **ISO rules** and **ISO tariff**.

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(a) the switchgear lineup connects a **transmission facility** to an **electric distribution system**; and

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Measurement Point Definition Record

4(1) The **legal owner** of a **revenue meter** must, where such **legal owner** requires a new **measurement point definition record** or an amendment to an existing **measurement point definition record**, submit a complete application form to the **ISO** prior to energizing the new or altered **revenue metering system**.

(2) The **ISO** must issue a **measurement point definition record** for a **measurement point** to the **legal owner** of the **revenue meter**, or to a **person** designated by the **legal owner** of the **revenue meter**, if the information in the application form submitted in accordance with subsection 2(1):

(a) is complete;

(b) allows for the proper measurement of **metered energy**, measurement of **metered demand**, and calculation of **apparent power** as required by the **ISO rules** and **ISO tariff**; and

(c) avoids a metering configuration that results in a deductive totalizing calculation for the **measurement point**.

Revenue Meter

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(a) the capacity of the **metering point** of the **revenue meter** is greater than or equal to 1.0 MVA; and

(b) the **revenue meter** is not the subject of a dispensation under the *Electricity and Gas Inspection Act*, RSC 1985 c E-4, as amended.

(2) The **legal owner** of a **revenue meter** must ensure that the **revenue meter** has an accuracy class rating that is less than or equal to 0.5% for Varhour measurement if:

(a) the capacity of the **metering point** of the **revenue meter** is greater than or equal to 1.0 MVA; and

(b) the **revenue meter** is not the subject of a dispensation under the *Electricity and Gas Inspection Act*, RSC 1985 c E-4, as amended.

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6(1) The **legal owner** of a **revenue meter** must ensure that the measurement transformer has an accuracy class rating less than or equal to 0.3% if:

(a) the capacity of the **metering point** of the **revenue meter** is greater than or equal to 1.0 MVA; and

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(a) is located and connected without compensation methods;

(b) produces a real **metering point**; and

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7(1) The **legal owner** of a **revenue meter** must retain metering data from the **revenue metering system**, including a record of final estimates and adjustments and the method used to perform the estimates or adjustments, for a period of at least 8 years.

(2) The **legal owner** of a **revenue meter** must process metering data for each **measurement point** in accordance with the algorithm in the **measurement point definition record** issued in accordance with subsection 2(2).

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8(1) The **legal owner** of a **revenue meter** must perform in-situ testing:

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Table 1 – In-situ Testing Frequency Based on Revenue Meter MW Class

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(ii) Greater than or equal to 5 MW and less than	(A) Every 4 years from the date of commissioning; or

MW Class	Testing Interval
or equal to 20 MW	(B) For existing revenue meters, every 4 years from the date of the previous in-situ test.

(2) The **legal owner** of a **revenue meter** must calculate the MW class in subsection 6(1)(b) as follows:

(a) determine the total active energy in MWh at the **measurement point** for the calendar year; and

(b) divide the total active energy determined in subsection 6(2)(a) by the number of settlement intervals in the same calendar year, including the intervals in which active energy is zero.

(3) The **legal owner** of a **revenue meter** must provide the results of the in-situ test performed in subsection 6(1) to the **ISO** if the test resulted in an error measurement of +/- 3%.

(4) Notwithstanding subsections 6(1), 6(2) and 6(3) above, the **legal owner** of a **revenue meter** must, at the request of the **ISO**, complete and report the results of an in-situ test for the **metering equipment** within 30 **days** of receiving the **ISO**'s request or within a mutually agreed time frame.

Measurement Data Corrections

9 The **legal owner** of a **revenue meter** must, if the **legal owner** discovers an error in measurement data, where the net difference in consumption from the measurement data previously submitted to the **ISO** is:

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(4) The **legal owner** of a **revenue meter** must notify the **ISO** in writing after completing the restoration of the **revenue metering system** in accordance with the plan referred to in subsection 8(3).

Revision History

Date	Description
202X-XX-XX	Included new subsection 2 to require legal owners of revenue meters to install revenue metering that will allow for appropriate financial settlement. Included new subsection 3 to require infrastructure required for feeder metering to be installed at substations that connect to electric distribution systems to implement the adjusted metering practice. Removed installation requirement under subsection 4 as redundant to new

Date	Description
	subsection 2.
2024-04-01	Amended, as approved in **Commission** Decision 28176-D01-2023 issued on June 13, 2023. See *Table of Concordance for the Transition from Division 502 to Division 503* on www.aeso.ca for further information regarding the change from Division 502 – Technical Requirements to Division 503 – Technical and Operating Requirements.
2021-03-18	Initial release.

August 17, 2023

To: The Market Surveillance Administrator, market participants and other interested parties ("Stakeholders")

Re: Stakeholder Comments on Letter of Notice – Development of Proposed Amendments to Section 503.17 of the ISO rules, Revenue Metering System ("Section 503.17") and Proposed Adjusted Metering Practice Implementation

Pursuant to Alberta Utilities Commission Rule 017, *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission*, written comments received from the Stakeholders in response to the Alberta Electric System Operator's ("AESO") July 21, 2023 Letter of Notice regarding proposed amended Section 503.17 and proposed Adjusted Metering Practice Implementation have been posted. Comments were received from the following Stakeholders:

1. AltaLink Management Ltd.;
2. Cities of Red Deer and Lethbridge;
3. DCG Consortium;
4. ENMAX Corporation;
5. EPCOR Distribution & Transmission Inc.;
6. IPCAA;
7. Office of the Utilities Consumer Advocate; and
8. Versorium Energy Ltd.

Thank you to all Stakeholders who participated in this process. All written comments received will be considered in the AESO's finalization of the proposed amended Section 503.17 and proposed Adjusted Metering Practice Implementation and responses to those comments will be posted on AESO Engage.

If you have any questions, please submit them to rules_comments@aeso.ca.

Sincerely,

Tom Sloan

Legal Manager, ISO Tariff and Market Rules
Legal and Regulatory Affairs
rules_comments@aeso.ca

Alberta Electric System Operator www.aeso.ca
Calgary Place, 2500, 330-5th Avenue SW Calgary, AB T2P 0L4
Phone: 403-539-2450 | Fax: 403-539-2949

Stakeholder Comment Matrix for the following:

1. **Proposed Adjusted Metering Practice Implementation; and**
2. **Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17")**

Period of Comment:	July 21, 2023 through August 11, 2023	**Contact:**	John Piotto
Comments From:	AltaLink Management Ltd. (AML)	**Phone:**	(403) 267-2103
Date:	[2023/08/11]	**Email:**	john.piotto@altalink.ca

Instructions:

1. Please fill out the section above as indicated.
2. Please refer back to the "AESO Materials" section on AESO Engage.
3. Please respond to the questions below and provide your specific comments, if any. Blank boxes will be interpreted as favourable comments.

The AESO is seeking comments from Stakeholders on the implementation of the Adjusted Metering Practice regarding the following matters:

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	When compared with the AESO's original AMP proposal, AML agrees that the AESO's proposal to implement AMP with legacy treatment does appear to reduce capital costs associated with implementation in the near term. AML generally agrees that the reduction of capital costs should be a priority for the purpose of implementing AMP. However, any project or initiative of this nature should be assessed through a number of factors which can include benefit-cost analysis, fairness, market implications, etc. To consider reduction of capital costs as a sole or primary objective may have the unintended outcome, for example, of leading to an option that results in higher rates for all than other options that should be considered. AML maintains that its alternative administrative proposal (see AML's stakeholder response of April 21, 2023) would eliminate the need for new feeder-level meters and the associated capital costs. Further, this alternative proposal could address the issue of billing determinant erosion occurring at DFO substations more completely than the AESO's proposal to implement AMP with or without legacy treatment because it would potentially resolve the lingering issue of feeder-lever meters only recording load net of DCG-supply on each feeder.

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	AML supports the AESO's attempts to address the erosion of load billing determinants that is occurring at the DFO substations. However, AML believes the AESO's AMP proposal only partially and insufficiently addresses the current and growing billing determinant erosion problem. In its stakeholder response of April 21, 2023, AML proposed an alternative that it believes would appropriately capture more DCG-related billing determinant erosion than the implementation of AMP without the need to install new feeder-level infrastructure/meters in existing or future substations. Respectfully, AML submits that the AESO has not thus far provided a thorough and testable analysis of the impacts that DCG has had on substation billing determinants and transmission rates. AML indicated in its April 21, 2023, stakeholder response the level of analysis and documentation that needs to be completed and provided to stakeholders. AML submits that the AESO should provide an Excel workbook, with all formulas and cell references intact, which demonstrates how all pertinent starting and final impact values are derived. This should be accompanied by all data sources and assumptions related to the analysis.
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	AML proposed a more thorough solution to the DCG billing determinant erosion concern in its April 21, 2023, stakeholder response. AML submits that the AESO should investigate this alternative solution which can be described as administrative or as an adjusted billing practice. This alternative would capture more DCG-related billing determinant erosion than what is being proposed by the AESO, perhaps sufficiently so, and would also eliminate the need to install new feeder-level meters. AML believes that the AESO should not be proceeding with any solution until AML's proposal has been further investigated and analyzed. This should be completed through the stakeholder process for regulatory efficiency purposes.

The AESO is seeking responses from Stakeholders to the following questions on the development of proposed amendments to Section 503.17:

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	As mentioned above, AML believes that what the AESO is proposing as a solution to AMP is insufficient and therefore does not support proceeding with the changes to this rule. To the extent the meter installation is absolutely required, AML does not have any concerns with the proposed changes as this relates to the AESO's proposed AMP implementation.
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	See response to question 4.

Period of Comment: July 21, 2023 through August 11, 2023	**Contact:** Jason Drenth, General Manager Lethbridge Electric Utility Jim Jorgensen, Red Deer Utilities Manager
Comments From: Cities or Red Deer and Lethbridge	**Phone:**
Date: 2023/08/10	**Email:** Jason.Drenth@lethbridge.ca Jim.Jorgensen@reddeer.ca

Instructions:

1. Please fill out the section above as indicated.
2. Please refer back to the "AESO Materials" section on AESO Engage.
3. Please respond to the questions below and provide your specific comments, if any. Blank boxes will be interpreted as favourable comments.

The AESO is seeking comments from Stakeholders on the implementation of the Adjusted Metering Practice regarding the following matters:

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	No. Proposing to amend ISO rules to require additional infrastructure without a justified reason for that infrastructure is inefficient. Without a justified reason, any expenditure greater than zero fails to minimize or reduce capital cost. The AESO has not provided any operational use or rationale for the additional infrastructure, other than to support AMP. The data provided by this additional metering is not required for the current approved tariff. The Commission has rejected a tariff proposal based on AMP and gave specific direction as to what steps are required for it to reconsider its decision. None of these steps involved changing ISO rules to incur capital expenditures before the Commission has a chance to reconsider its decision.
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	No.

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	We recommend that the AESO not proceed until it has first obtained Commission approval to charge a tariff that requires AMP. Until this condition is met, filing an application to change ISO rules causes an undue burden on stakeholders and the Commission.

The AESO is seeking responses from Stakeholders to the following questions on the development of proposed amendments to Section 503.17:

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	No. Please see responses to questions 1 and 3 for an explanation.
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	No.

Stakeholder Comment Matrix for the following:

1. **Proposed Adjusted Metering Practice Implementation; and**
2. **Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* (“Section 503.17”)**

Period of Comment:	July 21, 2023 through August 11, 2023	**Contact:**	Christine Runge
Comments From:	This response is a joint submission by BluEarth Renewables Inc., Elemental Energy Renewables Inc., and RWE Renewables Canada Holding Inc. (the “DCG Consortium”). This submission represents the consensus view of the group and is submitted on behalf of the group by Power Advisory LLC.	**Phone:**	403-613-7624
Date:	2023-08-11	**Email:**	crunge@poweradvioryllc.com

Instructions:

1. Please fill out the section above as indicated.
2. Please refer back to the “AESO Materials” section on AESO Engage.
3. Please respond to the questions below and provide your specific comments, if any. Blank boxes will be interpreted as favourable comments.

The AESO is seeking comments from Stakeholders on the implementation of the Adjusted Metering Practice regarding the following matters:

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	The DCG Consortium does not support approval and implementation of the AMP. The lowest cost option is to maintain the status quo. If costs were the top priority or a significantly high priority, the best approach would be to simply not file an application for the approval of the AMP. The Commission stated in Decision 27047-D01-2022 that "the AESO is not required by the Commission to file a further application proposing an implementation plan for the AMP." If the AESO is committed to filing an application for approval of the AMP, then it must ensure implementation of the AMP is fair and does not cause undue discrimination. Lower total cost of implementation for load customers is not an adequate justification for discrimination across generators. The Alberta market is designed such that load pays for transmission and distribution system costs allowing generators to compete on a level playing field in order to increase competition and efficiency in the energy market.
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	The DCG Consortium does not support approval and implementation of the AMP. The DCG Consortium is opposed to discriminatory legacy treatment for all the same reasons raised in the previous AMP proceeding regarding fairness between DCGs in Alberta. Such discriminatory treatment does not constitute rates that are not unduly preferential, arbitrarily or unjustly discriminatory, and impacts the fair, efficient and openly competitive operation of the electricity market by providing some generators with a competitive advantage over others and changing the factors leading to investment decisions, often after the fact. Discriminatory legacy treatment includes any instance where some DCGs are subject to the AMP before others are, including where substations requiring only administrative changes are subject to the AMP immediately and substations requiring physical changes continue not to be subject to the AMP at least in the short-term. These discriminatory impacts may be lessened but not entirely eliminated following the phase-out of DCG credits on January 1, 2026, as Rate STS charges, which can be a significant cost to generators, will continue to be significantly impacted by AMP.

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	The DCG Consortium does not support approval and implementation of the AMP. See responses to Questions 1 and 2 and the DCG Consortium's responses to the previous round of consultation.

The AESO is seeking responses from Stakeholders to the following questions on the development of proposed amendments to Section 503.17:

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	The revisions to the ISO tariff and ISO Rule 503.17 are consistent with the AESO's AMP proposal, with the exception noted in response to Question 5. Accordingly, the DCG Consortium's issues with the proposal (noted in response to Questions 1-3 above) would also apply to the relevant language in these two documents.

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	See response to Question 4, but if the changes are proceeded with the DCG Consortium offers the following comments: Section 3(1) added to ISO Rule 503.17 outlines how a substation would need to be feeder level meter ready, but the TFO would not actually be required to install the feeder level meters. The rule is not clear on when a substation would need to install the meters. It is assumed that the trigger would be the existence of reversing flows, but that is not clear from the rule language. Further, if the installation of new feeder level meters is triggered by the connection of a DCG which would result in forecast reversing flows, it is not clear which party would bear the costs of those meters. For investor certainly and consistent application across service territories, it should be made abundantly clear if these costs are meant to be a part of a DCG's local interconnection costs or if these costs are expected to be fully borne by the DFO as part of their system upgrade costs. For fair application between DCGs that have already connected and were not required to pay for metering costs, it would be just and reasonable for those costs to be charged to the DFO. If the AESO intends to suggest the costs should be paid as part of a DCG's local interconnection cost, it would be helpful, as part of the application for AMP implementation, to have a high-level estimate of what those costs may be given that these make ready costs would be borne by the DFO and only the actual costs of the meters remain. (It is assumed the previously provided estimates included all associated infrastructure as well as the meters themselves.)

Stakeholder Comment Matrix for the following:

1. **Proposed Adjusted Metering Practice Implementation; and**
2. **Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17")**

Period of Comment: July 21, 2023	through August 11, 2023	**Contact:**	Rose Ferrer
Comments From:	ENMAX Corporation	**Phone:**	
Date:	[2023/08/11]	**Email:**	RFerrer@enmax.com

Instructions:

1. Please fill out the section above as indicated.
2. Please refer back to the "AESO Materials" section on AESO Engage.
3. Please respond to the questions below and provide your specific comments, if any. Blank boxes will be interpreted as favourable comments.

The AESO is seeking comments from Stakeholders on the implementation of the Adjusted Metering Practice regarding the following matters:

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	At a high level, allowing utilities to exercise more operational flexibility and efficiency around when to install the feeder-level revenue meters appears to reduce the capital costs associated with implementing the AMP. The cost of implementation, along with providing continued flexibility to implement the feeder-level revenue metering when and where it is needed most should continue to be prioritized. This approach would recognize the different characteristics of each DFO service territory and aligns with the AUC requirement to make prudent investments that are in the best interests of consumers.

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	Yes, ENMAX supports the AESO's recommended approach that would require the installation of only the *infrastructure* for feeder level metering at the time switchgear is installed or replaced, and that complete revenue metering system at the feeder level would not be required unless there are reversing flows on the feeders. It is ENMAX's understanding that until a complete revenue metering system is required and subsequently installed, a customer will continue to totalize its demand at the Substation Level. Regarding the term *infrastructure*, ENMAX requests further clarity on whether the Point of Delivery requirements will differ if the metering point is at the Transformer or at the Feeder Level? What is the AESO's stance on sharing Potential Transformers from a Transformer metering point with a feeder metering point?
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	See comments below.

The AESO is seeking responses from Stakeholders to the following questions on the development of proposed amendments to Section 503.17:

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	**AMP – July 2023 AESO Background and Update to Stakeholders** The AESO noted in its July 2023 update to stakeholders that: *"New subsection 3.6(5) allows for legacy treatment from the AMP at DFO Substations. If the DFO Substation does not have feeder level metering or the infrastructure in place capable of easily installing revenue meters at the feeder level, then the AESO will allow an exception from subsections 3.6(2) and 3.6(3) since it would not be possible to meter the flows at the feeder level without a substantive and costly retrofit."* • ENMAX requests further clarity on what is meant by "If the DFO Substation […]". Given the metering and switchgear are all TFO assets, does the AESO mean "If a TFO substation where a DFO connects […]"? **Proposed ISO Rule 503.17** *"3(1) The legal owner of a revenue meter must install, at a minimum, all measurement transformers, associated wiring, and rack space required for a revenue metering system at each switchgear in a switchgear lineup if:* *(a) the switchgear lineup connects a transmission facility to an electric distribution system; and* *(b) the complete switchgear lineup is installed after <effective date>."* • The term "complete switchgear lineup" should be further defined by the AESO to ensure all stakeholders have the same understanding of what is within scope.
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	The effective date of these changes should allow enough lead time for parties to understand the scope of changes being proposed and adjust their internal processes accordingly. In ENMAX's view, the effective date should take effective no earlier than January 1, 2026. This would align with the expiration of the DCG credits and ensure no existing inflight projects are impacted from a cost and schedule perspective.

Stakeholder Comment Matrix for the following:

1. **Proposed Adjusted Metering Practice Implementation; and**
2. **Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17")**

Period of Comment:	July 21, 2023 through August 11, 2023	**Contact:**	George Newton
Comments From:	EPCOR Distribution & Transmission Inc.	**Phone:**	780-412-3715
Date:	2023/08/11	**Email**:	gnewton@epcor.com

Instructions:

1. Please fill out the section above as indicated.
2. Please refer back to the "AESO Materials" section on AESO Engage.
3. Please respond to the questions below and provide your specific comments, if any. Blank boxes will be interpreted as favorable comments.

The AESO is seeking comments from Stakeholders on the implementation of the Adjusted Metering Practice regarding the following matters:

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	EDTI agrees that the AESO's proposed legacy treatment approach minimizes capital costs by aligning the installation of AMP-compliant metering with switchgear life-cycle replacements or the construction of new switchgear. EDTI considers that this approach strikes an appropriate balance between additional capital costs and addressing the issue of billing determinant erosion.
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	Yes, EDTI supports the AESO's proposed implementation of AMP with legacy treatment as described in the AESO's July 21, 2023 stakeholder update materials.
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	EDTI appreciates the AESO's willingness to engage in meaningful consultation with impacted stakeholders to identify an appropriate path forward.

The AESO is seeking responses from Stakeholders to the following questions on the development of proposed amendments to Section 503.17:

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	EDTI agrees with the proposed amendments to Section 503.17.
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	EDTI does not have any additional comments regarding the proposed amendments to Section 503.17.

Stakeholder Comment Matrix for the following:

1. **Proposed Adjusted Metering Practice Implementation; and**
2. **Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17")**

Period of Comment: July 21, 2023	through August 11, 2023	**Contact:**	Richard Penn
Comments From: IPCAA		**Phone:**	403-9030=-7693
Date: [yyyy/mm/dd]		**Email**:	

Instructions:

1. Please fill out the section above as indicated.
2. Please refer back to the "AESO Materials" section on AESO Engage.
3. Please respond to the questions below and provide your specific comments, if any. Blank boxes will be interpreted as favourable comments.

The AESO is seeking comments from Stakeholders on the implementation of the Adjusted Metering Practice regarding the following matters:

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	IPCAA agrees with the AESO Decision to reduce capital costs associated with implementation and agrees with the recommended approach to utilize administrative practices whenever possible.
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	Yes, IPCAA continues to believe that reducing costs is a necessity.
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	IPCAA continues to iterate that in light of the many proposed changes that may be occurring in elements such as the Tariff that using administrative practices whenever possible should be the priority.

The AESO is seeking responses from Stakeholders to the following questions on the development of proposed amendments to Section 503.17:

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	IPCAA agrees that revenue meters need not be installed until absolutely needed. It would be helpful for the AESO to confirm if revenue meters are required or less accurate methods may be used.
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	

Stakeholder Comment Matrix for the following:

1. **Proposed Adjusted Metering Practice Implementation; and**
2. **Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17")**

Period of Comment:	July 21, 2023 through August 11, 2023	**Contact:**	Nola Ruzycki
Comments From:	Office of the Utilities Consumer Advocate	**Phone:**	403 476 4999
Date:	2023/08/10	**Email**:	

Instructions:

1. Please fill out the section above as indicated.
2. Please refer back to the "AESO Materials" section on AESO Engage.
3. Please respond to the questions below and provide your specific comments, if any. Blank boxes will be interpreted as favourable comments.

The AESO is seeking comments from Stakeholders on the implementation of the Adjusted Metering Practice regarding the following matters:

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	Yes, we agree that the recommended approach achieves the priority of reduction of capital costs associated with the implementation of AMP. The UCA believes the implementation of AMP is important to ensure the AESO address the artificial billing determinant erosion that occurs under the current measurement practice. The recommended approach is a reasonable compromise and balances reduction of capital costs while achieving most of benefits of implementing AMP.
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	Yes, legacy treatment will minimize meter cost while keeping the implementation of AMP moving forward, which is an important first step in measuring accurate feeder level flows.
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	As above: the UCA believes the implementation of AMP is important to ensure the AESO can address the artificial billing determinant erosion that occurs under the current measurement practice. The recommended approach is a reasonable compromise and balances reduction of capital costs while achieving most of the benefits of implementing AMP.

The AESO is seeking responses from Stakeholders to the following questions on the development of proposed amendments to Section 503.17:

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	yes
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	no

Stakeholder Comment Matrix for the following:

1. **Proposed Adjusted Metering Practice Implementation; and**
2. **Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17")**

Period of Comment:	July 21, 2023 through August 11, 2023	**Contact:**	Chris Codd
Comments From:	Versorium Energy Ltd.	**Phone:**	
Date:	2023-08-11	**Email**:	

Instructions:

1. Please fill out the section above as indicated.
2. Please refer back to the "AESO Materials" section on AESO Engage.
3. Please respond to the questions below and provide your specific comments, if any. Blank boxes will be interpreted as favourable comments.

The AESO is seeking comments from Stakeholders on the implementation of the Adjusted Metering Practice regarding the following matters:

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	The recommended approach is prioritizing immediate capital costs associated with implementing the AMP. The AESO's recommended approach will still drive capital cost increases in the future by requiring additional metering equipment at substations when they "undergo significant lifecycle alterations or rebuilds". The AESO should not implement the AMP if it is seeking to prioritize reductions in capital cost expenditures. We are supportive of reducing capital costs in the transmission system. However, the AESO's prioritization narrowly focuses on the immediate capital costs of implementing the AMP instead of overall transmission system costs. The recommended approach will likely increase overall transmission costs by making it more difficult for DFOs to implement NWAs.
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	No, we do not support the AESO's recommended approach for implementing the AMP. The AESO must make other changes to implement the AMP as proposed to address aggregation of DERs as the same substation and allow DFO totalization of DTS contracts to support development of NWAs.

	Development of a Proposed ISO Rule	Stakeholder Comments and/or Alternate Proposal
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	The AESO must address two deficiencies to implement the AESO's recommended approach. First, the AESO must alter ID 2012-008R to remove the forced aggregation of DERs owned by the same company on different distribution lines at the same substation. AMP is complicating a market participant's decision to aggregate or disaggregate multiple resources at the same location as contemplated by AUC Decision 790-D03-2015 and Section 501.10 of the ISO Rules. The combined impact of AMP, the associated tariff changes, and ID 2012-008R appear to prohibit a DER owner from disaggregating separate resources connecting to different distribution lines at the same substation, and this is in direct conflict with AUC Decision 790-D03-2015. Second, the AESO must develop a mechanism for a DFO's customers to realize benefits from third party NWAs. AMP as currently proposed will make it more difficult for a DFO-implemented NWA to reduce transmission costs for the implementing DFO's customers. One possible mechanism is for the AESO to totalize distribution line Rate STS and DTS contracts at the transformer or substation level where an NWA has been implemented. Another option to put NWAs and wires options on a level playing field would be to make NWAs eligible for investment under the ISO tariff. In the absence of such a mechanism, NWAs are less likely to pass a dual test of whether the overall system is better off and whether the implementing DFO's customers are better off.

The AESO is seeking responses from Stakeholders to the following questions on the development of proposed amendments to Section 503.17:

	AMP Implementation Plan	Stakeholder Comments and/or Alternate Proposal
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	The proposed amendments to Section 503.17 appear to have the potential to increase costs by requiring additional equipment to be installed at substations and make it more difficult to implement NWAs.
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	Has the AESO compared the cost of a new 25 kV switchgear building with and without the new requirement in the proposed Section 503.17?

August 25, 2023

To: The Market Surveillance Administrator, market participants and other interested parties ("Stakeholders")

Re: Alberta Electric System Operator Responses to Stakeholder Comments – Development of Proposed Amendments to Section 503.17 of the ISO rules, Revenue Metering System ("Section 503.17") and Proposed Adjusted Metering Practice ("AMP") Implementation

On July 21, 2023, the Alberta Electric System Operator ("AESO") notified Stakeholders of its proposed amended Section 503.17 and proposed approach to implementing the AMP. The AESO provided Stakeholders with an opportunity to submit written comments on proposed amended Section 503.17 as well as the AESO's proposed approach to implementing the AMP.

On August 17, 2023, the AESO posted comments received from Stakeholders regarding these two issues.

AESO Responses to Stakeholder Comments

In accordance with Alberta Utilities Commission ("Commission") Rule 017, *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission* the AESO is providing replies to Stakeholder comments. The AESO's responses to comments, including the AESO's rationale or basis for its position, and an explanation for why certain positions were rejected or accepted, are set out in the *Stakeholder Comment and AESO Response Matrix*.

Update to timing of AMP Application

The AESO previously advised Stakeholders that it would be filing its upcoming application for approval to implement the AMP, including proposed amended Section 503.17, by August 25, 2023. The AESO now intends to submit this application on or before August 31, 2023.

Related Materials

The following document can be accessed on AESO Engage:

1. *Stakeholder Comments and AESO Response Matrix* on the Proposed Adjusted Metering Practice Implementation and Proposed Amendments to Section 503.17.

If you have any questions, please submit them to rules_comments@aeso.ca.

Sincerely,

Tom Sloan

Legal Manager, ISO Tariff and Market Rules
Legal and Regulatory Affairs
rules_comments@aeso.ca

Stakeholder Comment and AESO Response Matrix for the following:

1. **Proposed Adjusted Metering Practice Implementation; and**
2. **Proposed Amendments to Section 503.17 of the ISO rules, *Revenue Metering System* ("Section 503.17")**

Date of Request for Comment:	July 21, 2023
Period of Comment:	July 21, 2023 through August 11, 2023

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
1.	The AESO's recommended approach for implementing the Adjusted Metering Practice prioritizes the reduction of capital costs associated with implementation. Do you agree that our recommended approach achieves that priority? Do you agree that the reduction of capital costs should be prioritized for the purposes of implementing the Adjusted Metering Practice?	**<u>1.1 AltaLink Management Ltd. (AML)</u>** When compared with the AESO's original AMP proposal, AML agrees that the AESO's proposal to implement AMP with legacy treatment does appear to reduce capital costs associated with implementation in the near term. AML generally agrees that the reduction of capital costs should be a priority for the purpose of implementing AMP. However, any project or initiative of this nature should be assessed through a number of factors which can include benefit-cost analysis, fairness, market implications, etc. To consider reduction of capital costs as a sole or primary objective may have the unintended outcome, for example, of leading to an option that results in higher rates for all than other options that should be considered. AML maintains that its alternative administrative proposal (see AML's stakeholder response of April 21, 2023) would eliminate the need for new feeder-level meters and the associated capital costs. Further, this alternative proposal could address the issue of billing determinant erosion occurring at DFO substations more completely than the AESO's proposal to implement AMP with or without legacy treatment because it would potentially resolve the lingering issue of feeder-lever meters only recording load net of DCG-supply on each feeder.	**<u>1.1 AESO Response</u>** AML's alternative proposal in their stakeholder response of April 21, 2023 would require the ISO tariff to be applied to the total site loads served by the distribution system, regardless of whether the distribution system obtained the energy to serve those loads from the transmission system or from DCG through the electric distribution system. This approach does not represent an alternative implementation of the adjusted metering practice (**AMP**), but rather a change to the billing determinants required by the ISO tariff and what the ISO tariff bills for, since transmission charges would apply to all flows on the AIES and not just system access service on the transmission system. The ISO tariff exists to recover transmission costs from market participants that obtain system access service through a connection to the transmission system, and the current ISO tariff specifically requires billing based on the flows at points of connection <u>to the transmission system</u>. Electric distribution service charges for flows that occur on the electric distribution system to customers connected to the distribution system fall under the purview of a DFO's distribution tariff. It is up to the DFO to determine how a DFO's transmission costs should be recovered from their distribution customers through their distribution tariff. Additionally, the AMP is not intended to address billing determinant erosion whatever the cause; it is only intended to address the *artificial* billing determinant erosion that arises

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
			due to the calculations under the current measurement practice that nets the flows to and from the transmission system. Any erosion of flows within a distribution system itself is outside the scope of the AMP approval under AUC Decision 22942-D02-2019. The AESO does not agree that there is a lingering issue of feeder-level meters recording the actual flows into and out of the substation on a feeder. These feeder-level meters correctly measure the flows at the demarcation point to the transmission system as required by the ISO tariff. The flows at the demarcation point to the transmission system are appropriately net of any load served by DCG on that feeder because that load is being served downstream of the transmission system. The AESO does not consider AML's alternative proposal to align with either the AUC's approval of the AMP in Decision 22942-D02-2019 or with how the AESO is required to provide system service service on the transmission system.
		<u>1.2 Cities of Red Deer and Lethbridge</u> No. Proposing to amend ISO rules to require additional infrastructure without a justified reason for that infrastructure is inefficient. Without a justified reason, any expenditure greater than zero fails to minimize or reduce capital cost. The AESO has not provided any operational use or rationale for the additional infrastructure, other than to support AMP. The data provided by this additional metering is not required for the current approved tariff. The Commission has rejected a tariff proposal based on AMP and gave specific direction as to what steps are required for it to reconsider its decision. None of these steps involved changing ISO rules to incur capital	**<u>1.2 AESO Response</u>** The AESO disagrees. The Commission approved the AMP in Decision 22942-D02-2019 for the justified reasons provided in that decision and the AMP continues to be required to address the artificial erosion of ISO tariff billing determinants. More recently, in Decision 27047-D01-2022, the Commission did not reject an ISO tariff proposal, but rather did not approve of the AESO's proposed plan for *implementing* the AMP. The AMP remains approved for the current ISO tariff pending an acceptable implementation plan. The AESO stated in its previous AMP implementation application in Proceeding 27047 that an amendment to the ISO rules was required to fully operationalize the AMP. The

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
		expenditures before the Commission has a chance to reconsider its decision.	AESO maintains that the additional infrastructure detailed in the proposed amendments to Section 503.17 remain required for the efficient implementation of the AMP.
		1.3 DCG Consortium The DCG Consortium does not support approval and implementation of the AMP. The lowest cost option is to maintain the status quo. If costs were the top priority or a significantly high priority, the best approach would be to simply not file an application for the approval of the AMP. The Commission stated in Decision 27047-D01-2022 that "the AESO is not required by the Commission to file a further application proposing an implementation plan for the AMP." If the AESO is committed to filing an application for approval of the AMP, then it must ensure implementation of the AMP is fair and does not cause undue discrimination. Lower total cost of implementation for load customers is not an adequate justification for discrimination across generators. The Alberta market is designed such that load pays for transmission and distribution system costs allowing generators to compete on a level playing field in order to increase competition and efficiency in the energy market.	**1.3 AESO Response** See AESO Response 1.2 for an explanation of the approval status of the AMP. In AUC Decision 27047-D01-2022, the AUC described a concern with the costs related to the AESO's plan for implementing the AMP. Therefore, and in response to stakeholder feedback, the AESO is proposing a plan to implement the AMP that prioritizes minimizing the capital costs *of implementation* while also addressing the artificial billing determinant erosion that is leading to the misallocation of transmission costs amongst ISO tariff ratepayers. While Decision 27047-D01-2022 did not require the AESO to file a further implementation plan, the AESO continues to believe that the AMP is in the public interest and required to ensure that the ISO tariff is just and reasonable. Please see AESO Response 2.3 for details on discrimination.
		1.4 ENMAX Corporation At a high level, allowing utilities to exercise more operational flexibility and efficiency around when to install the feeder-level revenue meters appears to reduce the capital costs associated with implementing the AMP. The cost of implementation, along with providing continued flexibility to implement the feeder-level revenue	**1.4 AESO Response** The AESO acknowledges ENMAX's comment.

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
		metering when and where it is needed most should continue to be prioritized. This approach would recognize the different characteristics of each DFO service territory and aligns with the AUC requirement to make prudent investments that are in the best interests of consumers.	
		1.5 EPCOR Distribution & Transmission Inc. (EDTI) EDTI agrees that the AESO's proposed legacy treatment approach minimizes capital costs by aligning the installation of AMP-compliant metering with switchgear life-cycle replacements or the construction of new switchgear. EDTI considers that this approach strikes an appropriate balance between additional capital costs and addressing the issue of billing determinant erosion.	**1.5 AESO Response** The AESO acknowledges EDTI's comment.
		1.6 IPCAA IPCAA agrees with the AESO Decision to reduce capital costs associated with implementation and agrees with the recommended approach to utilize administrative practices whenever possible.	**1.6 AESO Response** The AESO acknowledges IPCAA's comment. The AESO also notes that any administrative practice must still produce the billing determinants required by the ISO tariff. See AESO Response 1.1 for an example of an administrative practice that doesn't.
		1.7 Office of the Utilities Consumer Advocate (UCA) Yes, we agree that the recommended approach achieves the priority of reduction of capital costs associated with the implementation of AMP. The UCA believes the implementation of AMP is important to ensure the AESO address the artificial billing determinant erosion that occurs under the current measurement practice. The recommended approach is a reasonable compromise and balances reduction of capital costs while achieving most of benefits of implementing	**1.7 AESO Response** The AESO acknowledges the UCA's comment.

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
		AMP.	
		1.8 Versorium Energy Ltd. The recommended approach is prioritizing immediate capital costs associated with implementing the AMP. The AESO's recommended approach will still drive capital cost increases in the future by requiring additional metering equipment at substations when they "undergo significant lifecycle alterations or rebuilds". The AESO should not implement the AMP if it is seeking to prioritize reductions in capital cost expenditures. We are supportive of reducing capital costs in the transmission system. However, the AESO's prioritization narrowly focuses on the immediate capital costs of implementing the AMP instead of overall transmission system costs. The recommended approach will likely increase overall transmission costs by making it more difficult for DFOs to implement NWAs.	**1.8 AESO Response** The AESO is seeking to prioritize the reduction in capital cost expenditures *within the scope of implementing the AMP.* Implementing the AMP in the manner proposed by the AESO will minimize both the immediate and long-term capital costs of implementing the AMP by making use of planned substation work to realize efficiencies. The reduction of transmission system costs outside of the implementation of the AMP and ISO tariff are not within the scope of the AUC directions in either Decision 22942-D02-2019 or Decision 27047-D01-2022. Though reducing implementation costs was a priority, the goal of the AMP is to accurately quantify a market participants use of the system. SAS rates and charges that are based on accurate contract capacities and measurement of transmission system usage ensure that market participant billing appropriately reflects their use of the transmission system; and that market participants face incentives based on accurate signals. This is foundational to a rate design that supports efficient charges and encourages efficient use of the transmission system. The implementation of distribution NWAs (which the AESO assumes to refer to non wires alternatives) by a DFO is outside the scope of AMP implementation and, more broadly, beyond the purview of the AESO and the ISO tariff.
2.	Do you support the AESO's recommended approach for implementing the Adjusted Metering Practice?	**2.1 AltaLink Management Ltd. (AML)** AML supports the AESO's attempts to address the erosion of load billing determinants that is occurring at the DFO substations. However, AML believes the AESO's AMP proposal only partially and insufficiently addresses	**2.1 AESO Response** Please see AESO Response 1.1. The AESO does not have an Excel workbook with formulas and cell references to provide. The AESO's indicative

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
		the current and growing billing determinant erosion problem. In its stakeholder response of April 21, 2023, AML proposed an alternative that it believes would appropriately capture more DCG-related billing determinant erosion than the implementation of AMP without the need to install new feeder-level infrastructure/meters in existing or future substations. Respectfully, AML submits that the AESO has not thus far provided a thorough and testable analysis of the impacts that DCG has had on substation billing determinants and transmission rates. AML indicated in its April 21, 2023, stakeholder response the level of analysis and documentation that needs to be completed and provided to stakeholders. AML submits that the AESO should provide an Excel workbook, with all formulas and cell references intact, which demonstrates how all pertinent starting and final impact values are derived. This should be accompanied by all data sources and assumptions related to the analysis.	analysis to determine the impact of the AMP on 2021 ISO tariff billing involved cloning the AESO's Compliance and Data Management System (CDMS, the system that meter data managers submit data to) and the AESO's tariff billing system. Over 30 million records and over 20 million calculations in those systems generated the 2021 billing determinants and bills under the AMP. The AESO notes that its indicative analysis largely mirrors the "alternative approach" to calculate billing determinants proposed by AML (i.e. to add back **all** DCG output to the billing determinants) due to the assumption that DCG was located on dedicated feeders. Assuming that DCG is on a dedicated feeder means that DCG "does not net with the load before entering the substation" as AML's alternative approach requires. One of the reasons why the AESO's annual bill impacts ($) is lower than AML's is that the AESO applied the Rate DTS rates that would have been used for billing had the AMP been in place for 2021, which are lower than the 2023 ISO tariff rates that AML used in its April 21, 2023 analysis. The AESO will provide a detailed explanation of the analysis methodology in its upcoming filing.
		<u>2.2 Cities of Red Deer and Lethbridge</u> No.	**<u>2.2 AESO Response</u>** The AESO acknowledges the Cities' comment.
		<u>2.3 DCG Consortium</u> The DCG Consortium does not support approval and implementation of the AMP. The DCG Consortium is opposed to discriminatory legacy treatment for all the same reasons raised in the previous AMP proceeding regarding fairness between DCGs in	**<u>2.3 AESO Response</u>** The AESO does not agree. In the context of the ISO tariff, the AESO must consider fairness from the perspective of all transmission market participants. Substations where billing determinants do not accurately reflect the flows to and from the transmission

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
		Alberta. Such discriminatory treatment does not constitute rates that are not unduly preferential, arbitrarily or unjustly discriminatory, and impacts the fair, efficient and openly competitive operation of the electricity market by providing some generators with a competitive advantage over others and changing the factors leading to investment decisions, often after the fact. Discriminatory legacy treatment includes any instance where some DCGs are subject to the AMP before others are, including where substations requiring only administrative changes are subject to the AMP immediately and substations requiring physical changes continue not to be subject to the AMP at least in the short-term. These discriminatory impacts may be lessened but not entirely eliminated following the phase-out of DCG credits on January 1, 2026, as Rate STS charges, which can be a significant cost to generators, will continue to be significantly impacted by AMP.	system are an exception to how the ISO tariff should apply to all transmission market participants. As of July 1, 2023, there are approximately 55 – 77 substations that provide SAS to an electric distribution system where billing determinants do not accurately reflect transmission flows. Implementation of the AMP would significantly reduce these exceptions to only a small number of substations where SAS would not comply with the AMP (under the proposed AMP implementation, the AESO expects that only 5 – 12 substations where billing determinants would not accurately reflect transmission flows). However, since the AESO has a public interest mandate, the AESO has also considered the impact of the AMP on other types of market participant groups. The AESO acknowledges that DCG connected downstream of substations that are not compliant with the AMP will see different treatment than those at substations that are compliant, discriminatory treatment does not apply solely to DCG. However, from the perspective of DCG credits, the discriminatory impacts are also mitigated by the fact that DCG credits are not available in all distribution service areas. From a Rate STS perspective, the AESO considers that the AMP would support a level playing field across all generation market participants, whether distribution or transmission connected since currently, generation that is connected to a distribution system may not be flowed through any Rate STS charges (or credits) and if they are, the billing determinants for Rate STS do not accurately reflect the flows onto the transmission system. The AESO also notes that the bill for Rate STS is dependent upon the POS specific loss factor, which may vary from +12% to -12%. While the bill for Rate STS may result in a significant charge, it may also result in a significant credit.

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
			The AESO will include the tradeoffs of the alternative approaches for implementing AMP, including discriminatory treatment of **all** customers, in its upcoming application.
		2.4 ENMAX Corporation Yes, ENMAX supports the AESO's recommended approach that would require the installation of only the infrastructure for feeder level metering at the time switchgear is installed or replaced, and that complete revenue metering system at the feeder level would not be required unless there are reversing flows on the feeders. It is ENMAX's understanding that until a complete revenue metering system is required and subsequently installed, a customer will continue to totalize its demand at the Substation Level. Regarding the term infrastructure, ENMAX requests further clarity on whether the Point of Delivery requirements will differ if the metering point is at the Transformer or at the Feeder Level? What is the AESO's stance on sharing Potential Transformers from a Transformer metering point with a feeder metering point?	**2.4 AESO Response** Until a complete revenue metering system is required, the AESO will require that the measurement for a DFO's SAS be based on the most granular level of metering available. Practically speaking, this means that for a substation that only has transformer metering available, totalization will occur at the transformer level, without netting between transformers. "Infrastructure" is referring to the infrastructure to accommodate the installation of a revenue meter at the feeder level, that would be problematic to install at a later date. This infrastructure does not need to be unique and may be shared between metering points so long as the installation complies with all technical rules. Specifically, a transformer metering point may share the potential transformer with a feeder metering point so long as it is installed in a suitable location for the proper measurement of energy for each metering point.
		2.5 EPCOR Distribution & Transmission Inc. (EDTI) Yes, EDTI supports the AESO's proposed implementation of AMP with legacy treatment as described in the AESO's July 21, 2023 stakeholder update materials.	**2.5 AESO Response** The AESO acknowledges EDTI's comment.
		2.6 IPCAA Yes, IPCAA continues to believe that reducing costs is a necessity.	**2.6 AESO Response** The AESO acknowledges IPCAA's comment.

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
		2.7 Office of the Utilities Consumer Advocate (UCA) Yes, legacy treatment will minimize meter cost while keeping the implementation of AMP moving forward, which is an important first step in measuring accurate feeder level flows.	**2.7 AESO Response** The AESO acknowledges the UCA's comment.
		2.8 Versorium Energy Ltd. No, we do not support the AESO's recommended approach for implementing the AMP. The AESO must make other changes to implement the AMP as proposed to address aggregation of DERs as the same substation and allow DFO totalization of DTS contracts to support development of NWAs.	**2.8 AESO Response** Please see AESO Response 3.8.
3.	Do you have any comments on the AESO's recommendation of how the Adjusted Metering Practice should be implemented?	**3.1 AltaLink Management Ltd. (AML)** AML proposed a more thorough solution to the DCG billing determinant erosion concern in its April 21, 2023, stakeholder response. AML submits that the AESO should investigate this alternative solution which can be described as administrative or as an adjusted billing practice. This alternative would capture more DCG-related billing determinant erosion than what is being proposed by the AESO, perhaps sufficiently so, and would also eliminate the need to install new feeder-level meters. AML believes that the AESO should not be proceeding with any solution until AML's proposal has been further investigated and analyzed. This should be completed through the stakeholder process for regulatory efficiency purposes.	**3.1 AESO Response** Please see AESO Response 1.1.

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
		<u>3.2 Cities of Red Deer and Lethbridge</u> We recommend that the AESO not proceed until it has first obtained Commission approval to charge a tariff that requires AMP. Until this condition is met, filing an application to change ISO rules causes an undue burden on stakeholders and the Commission.	**<u>3.2 AESO Response</u>** Please see AESO Response 1.2.
		<u>3.3 DCG Consortium</u> The DCG Consortium does not support approval and implementation of the AMP. See responses to Questions 1 and 2 and the DCG Consortium's responses to the previous round of consultation.	**<u>3.3 AESO Response</u>** Please see AESO Response 1.3 and 2.3.
		<u>3.4 ENMAX Corporation</u> See comments below.	**<u>3.4 AESO Response</u>** Please see AESO Response 4.4 and 5.4.
		<u>3.5 EPCOR Distribution & Transmission Inc. (EDTI)</u> EDTI appreciates the AESO's willingness to engage in meaningful consultation with impacted stakeholders to identify an appropriate path forward.	**<u>3.5 AESO Response</u>** The AESO acknowledges EDTI's comment.
		<u>3.6 IPCAA</u> IPCAA continues to iterate that in light of the many proposed changes that may be occurring in elements such as the Tariff that using administrative practices whenever possible should be the priority.	**<u>3.6 AESO Response</u>** Please see the response to AESO 1.6. The AESO believes that the recommended AMP implementation maximizes the use of administrative practices to realize the benefit of the AMP while minimizing the capital costs incurred. The AESO also notes that this approach will delay and minimize the capital costs significantly as the physical work required to implement the AMP will not be undertaken until it is efficient

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
			and more cost-effective to do so.
		<u>3.7 Office of the Utilities Consumer Advocate (UCA)</u> As above: the UCA believes the implementation of AMP is important to ensure the AESO can address the artificial billing determinant erosion that occurs under the current measurement practice. The recommended approach is a reasonable compromise and balances reduction of capital costs while achieving most of the benefits of implementing AMP.	**<u>3.7 AESO Response</u>** The AESO acknowledges the UCA's comment.
		<u>3.8 Versorium Energy Ltd.</u> The AESO must address two deficiencies to implement the AESO's recommended approach. First, the AESO must alter ID 2012-008R to remove the forced aggregation of DERs owned by the same company on different distribution lines at the same substation. AMP is complicating a market participant's decision to aggregate or disaggregate multiple resources at the same location as contemplated by AUC Decision 790-D03-2015 and Section 501.10 of the ISO Rules. The combined impact of AMP, the associated tariff changes, and ID 2012-008R appear to prohibit a DER owner from disaggregating separate resources connecting to different distribution lines at the same substation, and this is in direct conflict with AUC Decision 790-D03-2015. Second, the AESO must develop a mechanism for a DFO's customers to realize benefits from third party NWAs. AMP as currently proposed will make it more difficult for a DFO-implemented NWA to reduce transmission costs for the implementing DFO's customers. One possible mechanism is for the AESO to totalize distribution line Rate STS and DTS contracts at the	**<u>3.8 AESO Response</u>** Information Document 2012-008R, Energy Offers and Bids, relating to Section 203.1 of the ISO rules, Offers and Bids for Energy is out of scope for the ISO tariff AMP. However, to provide additional clarity, the AESO notes the following: The AESO does not believe that the AMP is in direct conflict with AUC Decision 790-D03-2015, or that it complicates a market participants decision to aggregate or disaggregate generating units per Section 501.10 of the ISO rules, Transmission Loss Factors (**Section 501.10**) or that the AMP prohibits a DER owner from disaggregating separate resources connected at the same substation. Section 501.10 and Decision 790-D03-2015 do require that for each location that is a POS of SAS under Rate STS, a market participant must ensure that all generating units connected through that single location must have their energy submitted in the energy market as part of a single source asset, which is owned by a single company. However, Section 501.10 and Decision 790-D03-2015 contemplated that there is a disconnect for DCG: SAS is provided at a POS for a DFO at their point of connection to the transmission system but the energy market supply point for offers into the energy market

	Proposed Adjusted Metering Practice Implementation	Stakeholder Comments and/or Alternate Proposal	AESO Response
		transformer or substation level where an NWA has been implemented. Another option to put NWAs and wires options on a level playing field would be to make NWAs eligible for investment under the ISO tariff. In the absence of such a mechanism, NWAs are less likely to pass a dual test of whether the overall system is better off and whether the implementing DFO's customers are better off.	is at the DCG site. In recognition of this disconnect, subsection 5(3) of Section 501.10 sets out that all DCG connected to part of an electric distribution already "satisfy the single owner, single enterprise, and single source asset requirements of subsection 5(2) above, including any of those generating units and aggregated generating facilities that have energy submitted in the energy market as a *separate source asset*." Therefore, the number of STS' at a substation does not impact whether there can be one, or multiple source assets at that substation. The AESO also notes that under either measurement practice (the current or the AMP), market participants are able to elect as many points of supply (i.e. STS') at a substation as they wish, as long as the appropriate metering is in place. Please see AESO response 1.8 regarding NWAs. The implementation of the AMP ensures that transmission costs more accurately reflect the flows to and from the transmission system. Totalizing Rate STS and Rate DTS at the transformer or substation level would underrepresent the flows to and from the transmission system and therefore lead to inaccurate transmission costs.

	Proposed Amendments to Section 503.17 of the ISO rules, Revenue Metering System	Stakeholder Comments and/or Alternate Proposal	AESO Response
4.	Do you agree with the proposed amendments to Section 503.17? Please explain.	**4.1 AltaLink Management Ltd. (AML)** As mentioned above, AML believes that what the AESO is proposing as a solution to AMP is insufficient and therefore does not support proceeding with the changes to this rule. To the extent the meter installation is absolutely required, AML does not have any concerns with the proposed changes as this relates to the AESO's proposed AMP implementation.	**4.1 AESO Response** Please see AESO Response 1.1. The AESO acknowledges AML's comment.
		4.2 Cities of Red Deer and Lethbridge No. Please see responses to questions 1 and 3 for an explanation.	**4.2 AESO Response** Please see AESO Response 1.2.
		4.3 DCG Consortium The revisions to the ISO tariff and ISO Rule 503.17 are consistent with the AESO's AMP proposal, with the exception noted in response to Question 5. Accordingly, the DCG Consortium's issues with the proposal (noted in response to Questions 1-3 above) would also apply to the relevant language in these two documents.	**4.3 AESO Response** Please see AESO Response 1.3, 2.3 and 5.3.
		4.4 ENMAX Corporation **AMP – July 2023 AESO Background and Update to Stakeholders** The AESO noted in its July 2023 update to stakeholders that: *"New subsection 3.6(5) allows for legacy treatment from*	**4.4 AESO Response** The AESO has defined a substation that connects to an electric distribution system as a "DFO substation" throughout its engagement material as a shorthand term. This does refer to the transmission substation owned and operated by the TFO where distribution feeders connect. The shorthand term is not used in the proposed amendments to the ISO tariff or

	Proposed Amendments to Section 503.17 of the ISO rules, Revenue Metering System	Stakeholder Comments and/or Alternate Proposal	AESO Response
		the AMP at DFO Substations. If the DFO Substation does not have feeder level metering or the infrastructure in place capable of easily installing revenue meters at the feeder level, then the AESO will allow an exception from subsections 3.6(2) and 3.6(3) since it would not be possible to meter the flows at the feeder level without a substantive and costly retrofit." • ENMAX requests further clarity on what is meant by "If the DFO Substation […]". Given the metering and switchgear are all TFO assets, does the AESO mean "If a TFO substation where a DFO connects […]"? **Proposed ISO Rule 503.17** *"3(1) The legal owner of a revenue meter must install, at a minimum, all measurement transformers, associated wiring, and rack space required for a revenue metering system at each switchgear in a switchgear lineup if:* *(a) the switchgear lineup connects a transmission facility to an electric distribution system; and* *(b) the complete switchgear lineup is installed after <effective date>."* • The term "complete switchgear lineup" should be further defined by the AESO to ensure all stakeholders have the same understanding of what is within scope.	Section 503.17 of the ISO rules. The AESO will include further clarification on the term "complete switchgear lineup" in its upcoming filing, and will also consider whether guidance could be provided in an information document to Section 503.17. However, the intent is that 3(1) would not be triggered by the replacement or installation of individual components within a single switchgear bay of a full switchgear lineup.
		<u>4.5 EPCOR Distribution & Transmission Inc. (EDTI)</u> EDTI agrees with the proposed amendments to Section 503.17.	**<u>4.5 AESO Response</u>** The AESO acknowledges EDTI's comment.

	Proposed Amendments to Section 503.17 of the ISO rules, Revenue Metering System	Stakeholder Comments and/or Alternate Proposal	AESO Response
		4.6 IPCAA <No comment provided>	**4.6 AESO Response** <No response required>
		4.7 Office of the Utilities Consumer Advocate (UCA) Yes	**4.7 AESO Response** The AESO acknowledges the UCA's comment.
		4.8 Versorium Energy Ltd. The proposed amendments to Section 503.17 appear to have the potential to increase costs by requiring additional equipment to be installed at substations and make it more difficult to implement NWAs.	**4.8 AESO Response** The AESO acknowledges Versorium's comments regarding costs. While the proposed implementation of the AMP will incur costs in the future, the AESO's proposal maximizes the use of administrative practices to realize the benefit of the AMP while minimizing the capital costs incurred. Please see AESO Response 3.8 regarding NWAs.
5.	Do you have any additional comments regarding the proposed amendments to Section 503.17?	**5.1 AltaLink Management Ltd. (AML)** See response to question 4.	**5.1 AESO Response** Please see AESO Response 4.1.
		5.2 Cities of Red Deer and Lethbridge No.	**5.2 AESO Response** The AESO acknowledges the Cities' comment.
		5.3 DCG Consortium See response to Question 4, but if the changes are proceeded with the DCG Consortium offers the following comments: Section 3(1) added to ISO Rule 503.17 outlines how a substation would need to be feeder level meter ready, but the TFO would not actually be required to install the feeder level meters. The rule is not clear on when a	**5.3 AESO Response** The proposed revisions to the ISO tariff and section 503.17 of the ISO rules work in concert to determine the need to install feeder level meters: • Proposed subsection 2(1) of 503.17 requires a revenue metering system that allows for proper settlement per the ISO tariff;

	Proposed Amendments to Section 503.17 of the ISO rules, Revenue Metering System	Stakeholder Comments and/or Alternate Proposal	AESO Response
		substation would need to install the meters. It is assumed that the trigger would be the existence of reversing flows, but that is not clear from the rule language. Further, if the installation of new feeder level meters is triggered by the connection of a DCG which would result in forecast reversing flows, it is not clear which party would bear the costs of those meters. For investor certainly and consistent application across service territories, it should be made abundantly clear if these costs are meant to be a part of a DCG's local interconnection costs or if these costs are expected to be fully borne by the DFO as part of their system upgrade costs. For fair application between DCGs that have already connected and were not required to pay for metering costs, it would be just and reasonable for those costs to be charged to the DFO. If the AESO intends to suggest the costs should be paid as part of a DCG's local interconnection cost, it would be helpful, as part of the application for AMP implementation, to have a high-level estimate of what those costs may be given that these make ready costs would be borne by the DFO and only the actual costs of the meters remain. (It is assumed the previously provided estimates included all associated infrastructure as well as the meters themselves.)	• Proposed subsections 3.6(2) and 3.6(3) of the ISO tariff require that SAS agreements are based on flows to and from the transmission system at each feeder; and • Proposed subsection 3.6(5) allows for an exception to 3.6(2) and 3.6(3) only if feeder meters or infrastructure are not in place. Taken together, if the infrastructure for feeder meters is in place when reversing flows arise, the exception in 3.6(5) does not apply, and 2(1) of 503.17 will require the installation of feeder meters to allow for the settlement required by 3.6(2) and 3.6(3) of the ISO tariff. This relationship will be detailed in a future information document. The AESO is investigating the incremental cost of the infrastructure required in proposed Section 3(1) of 503.17 as well as the subsequent addition of meters and will include the results in its upcoming application, along with the proposed cost treatment.
		<u>5.4 ENMAX Corporation</u> The effective date of these changes should allow enough lead time for parties to understand the scope of changes being proposed and adjust their internal processes accordingly. In ENMAX's view, the effective date should	**<u>5.4 AESO Response</u>** The AESO considers January 1, 2025 to be sufficient time to allow for implementation of the AMP by impacted parties, and an implementation plan will be filed in its upcoming application including details on the treatment of in-flight projects.

	Proposed Amendments to Section 503.17 of the ISO rules, Revenue Metering System	Stakeholder Comments and/or Alternate Proposal	AESO Response
		take effective no earlier than January 1, 2026. This would align with the expiration of the DCG credits and ensure no existing inflight projects are impacted from a cost and schedule perspective.	The AESO also intends to include its upcoming application alternative timings and associated trade-offs for consideration by the Commission.
		5.5 EPCOR Distribution & Transmission Inc. (EDTI) EDTI does not have any additional comments regarding the proposed amendments to Section 503.17.	**5.5 AESO Response** The AESO acknowledges EDTI's comment.
		5.6 IPCAA IPCAA agrees that revenue meters need not be installed until absolutely needed. It would be helpful for the AESO to confirm if revenue meters are required or less accurate methods may be used.	**5.6 AESO Response** The AESO confirms that for any billing of energy flows, those energy flows must be derived from revenue metered source data and adhere to all Measurement Canada requirements.
		5.7 Office of the Utilities Consumer Advocate (UCA) no	**5.7 AESO Response** The AESO acknowledges the UCA's comment.
		5.8 Versorium Energy Ltd. Has the AESO compared the cost of a new 25 kV switchgear building with and without the new requirement in the proposed Section 503.17?	**5.8 AESO Response** The AESO has discussed the incremental work and cost of installing meters at the feeder level when switchgear is being replaced and will include additional details in its upcoming application.