

Minutes from Stakeholder Consultation Session on the Development of the Proposed New Section 502.10 of the ISO rules, *Revenue Metering Technical Requirements*

Location: AESO BP Location, Meeting Room 6006, 6th floor of the BP Centre located at 240 – 4th Ave SW Calgary, AB T2P 2H8

Date: December 11, 2019

Time: 9:00 a.m. to 3:00 p.m.

Attendees:

Company
Alberta Electric System Operator (“AESO”)
AltaLink Management Ltd. (“AltaLink”)
ATCO Electric Ltd. (“ATCO Electric”)
Canadian Natural Resources Limited (“CNRL”)
EPCOR Distribution & Transmission Inc. (“EDTI”)
ENMAX Power Corporation (“EPC”)
FortisAlberta Inc. (“Fortis”)
Heartland Generation (“Heartland”)
Rodan Energy Solutions (“Rodan”)
Suncor Energy
TransAlta Corporation (“TransAlta”)

1 Consultation Session Overview and Introductions [slides 2 to 8]

- a The AESO welcomed stakeholders to the session, reviewed safety procedures, reviewed the agenda and provided an overview of the current consultation session.
- b The AESO reviewed the consultation session objectives and stakeholder engagement expectations, and provided instructions for asking questions in person and through the webinar.
- c Attendees introduced themselves.

2 Current ISO Rule Development Process [slides 9 to 14]

- a The AESO reviewed its ISO rule development process and the consultation activities for proposed new Section 502.10 of the ISO rules, *Revenue Metering Technical Requirements* (“Section 502.10” or the “draft Rule”) that occurred before the Alberta Utilities Commission (“AUC”) amended its AUC Rule 017. The AESO explained it may stay in the consultation stage for a while depending on the feedback it receives at the consultation session. Once the AESO has received and understood all stakeholder

feedback, it will proceed to amend the draft Rule, solicit formal stakeholder feedback, and file an application with the AUC in which it will request the approval of Section 502.10.

- b The AESO clarified that for each rule requirement it will go through the description, alternatives considered (where applicable) and the AESO's rationale for determining its preferred alternative.
- c There were no comments from attendees.

3 Establishing Revenue Metering Requirements Guiding Principles [slide 16]

- a The AESO presented a summary of guiding principles for how it approached the draft Rule. Namely:
 - i. The draft Rule is focused on the minimum technical requirements for revenue metering from the AESO's perspective. Each of the provisions of the draft Rule are authoritative in nature and are measurable to ensure that legal owners know what to demonstrate compliance to. The draft Rule does not contain "best practices" or other guidance information because this content is not authoritative.
 - ii. The draft Rule is part of a much larger regulatory Provincial and Federal framework that applies to metering, so the AESO tried to avoid unnecessary duplication with other regulatory requirements.
 - iii. The draft Rule is a translation of the existing standard Measurement System Standard into a rule and based on the extensive work of the 2017 technical work group (see meeting minutes posted with the draft Rule). The AESO wanted to avoid making change for the sake of making change.
 - iv. The draft Rule intentionally avoids overly-prescriptive methodologies in ISO rules in order to preserve flexibility and avoid having to go back to the AUC for amendments.
 - v. The draft Rule considers the stakeholder feedback, including cost considerations, provided by the 2017 technical work group, as well as comments received following the introduction of AUC Rule 017.

4 Applicability [slide 17]

- a In 2017, the technical work group proposed to list the functional entities that the draft Rule applied to (e.g., legal owner of transmission facility and legal owner of an electric distribution system). The AESO explained that simplifying the applicability of the draft Rule to "legal owner of a revenue meter", along with the amended definition for "revenue meter": (1) creates more flexibility in terms of applicability; and (2) clearly identifies that the party responsible for complying with the rule is the owner of the physical meter, as the AESO understands that there can be different ownership splits of equipment.
- b Fortis commented that the proposed applicability is too broad. All meters purchased moving forward have interval capability. The concern is that the proposed definition of "revenue meter" could include all meters in Alberta. Fortis referred to the definitions of "interval data" under Measurement Canada series E31 documents and cautioned carefully distinguishing between "interval meter" and "interval data".
 - i. The AESO confirmed that the rule is intended to apply to interval meters used to generate metering data that is used for the AESO's financial settlement process, not cumulative meters. The AESO asked Fortis if the reference to AESO's financial

settlement in the definition addressed any of Fortis' concerns about applicability, and if Fortis had any recommendations to make the definition more clear.

- ii. Fortis explained that every meter is used for financial settlement. Fortis wanted to bring an understanding that all meters in the future have interval capabilities. The Federal government is authorizing the use of that interval data from all meters. Fortis also mentioned that discussions in the Distribution System Inquiry surrounding "time of use" and how that will be based on interval meters. If that is the intent is for the rule to apply to all meters in the province then that is fine, but if it isn't then there is a need for clarification of what the intended use of the interval data is outside of the meter. Fortis did not have any recommendations for revising the definition. Previously this working group spent a lot of time discussing who the owners were, but it never reached a consensus. This definition broadens it a bit too far.
 - iii. The AESO mentioned that the applicability from the 2017 technical work group proposal may not cover emerging technologies, such as energy storage. The AESO wanted to simplify the applicability and provide greater flexibility.
- c TransAlta commented that the language "as defined by the AESO" in the "revenue meter" definition indicates that there is a process the AESO has to deem applicability. TransAlta questioned whether there would be uncertainty for the participant or legal owners regarding applicability. Would the AESO allow them to go through process to deem whether the rule is applicable or not?
- i. The AESO clarified that the "as defined by AESO" pertains to the frequency of the interval (e.g., 15 minutes). The AESO didn't refer to 15-minute intervals in the definition in case there is a move to a shorter settlement period in the future.
- d Rodan commented that the term "revenue meter" is ambiguous. Rodan questioned whether it would be clearer to use "revenue metering system" instead of "revenue meter" because the draft Rule also applies to measurement instruments.
- i. The AESO considered making the rule applicable to the "legal owner of a revenue metering system". However, ownership can be split between the communications aspects of the system and the physical equipment, so the AESO was concerned about who would be responsible for rule compliance. Like other Part 500 ISO rules, the applicability should identify a singular entity. The AESO clarified that the proposed applicability still allows the legal owner the freedom to go out and contract with other providers.
 - ii. The AESO further explained that the purpose of the rule is to set a set of minimum technical requirements to revenue meters that provide settlement data to AESO. The focus is not on cumulative meters, nor on direct retail customer because these meters do not provide the same data. If we go back to the definition that was made a couple of years ago, it is the definition of who provides data directly to the AESO.
 - iii. Rodan asked if there will be specific provisions specifying that the legal owner is free to contract because the draft rule does not contain language around meter service providers. Rodan also asked if the AESO contemplated situations where there is a rental meter, or a metering point owned by an entity other than the owner.
 - iv. The AESO reiterated that the applicability aligns with other Part 500 ISO rules (i.e., singular entity) and there is no prohibition against contracting with third party service providers. The AESO requires certain things for the reliability and functions of the system, and this means being able to zero in on an entity that is accountable for rule compliance. The AESO also re-emphasized that the proposed applicability is also intended to

preserve flexibility. The AESO asked other participants for comment on Rodan's questions.

- v. Fortis explained that there are differences in dealing with farm co-ops, and REAs, where there is a service provider that has legal ownership under a contract or under the EGIA, but the true owner of the asset may be a different entity. The AESO similarly responded that the proposed applicability preserves flexibility. The AESO requires certain things for the reliability and functions of the system, and this means being able to zero in on an entity that is accountable.
- e The AESO asked if Rodan thought the term or, or definition for, "revenue meter" was ambiguous. The AESO asked if Fortis agreed with Rodan given Fortis' earlier comments about the definition.
- i. Rodan responded that it is the term that is ambiguous.
 - ii. Fortis responded that as long as "revenue meter" is defined somewhere, it is fine. It needs to be easy for the market participants to know what it means.
 - iii. ATCO Electric supported the definition of "revenue meter", subject to minor changes to indicate that the meter is defined by the measurement point definition record ("MPDR").
 - iv. Any revenue meter defined by the AESO has a MPDR and measurement point ID ("MPID").
 - v. TransAlta noted that the proposed definition of "revenue meter" includes language to this effect and added that the rule will not apply to meters one might have between commercial parties.
 - vi. Rodan noted that Measurement Canada's definition of revenue meter includes metering installation.
 - vii. Fortis confirmed that the Federal act looks at an installation as a revenue meter. It is either one discrete device in a residential service or if there is a CT, PT or any ancillary devices, the entire installation is considered a revenue meter, as per the EGIA/R.
 - viii. The AESO responded that it consulted Measurement Canada, EGIA, AUC Rule 021: *Settlement System Code Rules* ("AUC Rule 021"), and the *Electric Utilities Act* ("EUA"), among others, in the development of the proposed definition.
 - ix. The AESO noted that its preference was to not link the MPDR and revenue meter definitions in order to avoid circular references.

5 Successor to Prior Requirements

- a The AESO explained that section 2 is boilerplate in the Part 500 ISO rules used to retire former standards. The AESO did not identify any need to grandfather any existing revenue meters because the requirements were either carried over from the Measurement System Standard or made less stringent. However, subsection 4(1) was intentionally qualified to ensure legal owners with existing MPDRs do not need to re-apply for another MPDR after the rule comes into effect.
- b Rodan generally agreed with making standards less stringent, but questioned if this limited the discussion about imposing more stringent rules in certain places. If more stringent requirements were imposed, would there be a requirement for grandfathering?

- i. The AESO responded that the draft Rule represents the minimum technical requirements and it is the freedom of the legal owner if they want to implement stricter controls or “best practices”. If there is an identified need for more stringent metering requirements, grandfathering consideration may arise. It depends on context.

6 Functional Specification [slide 18]

- a. The AESO noted that these are boilerplate requirements in the Part 500 ISO rules relating to the functional specifications that dictate project specific technical requirements. If proposed Section 103.14 of the ISO rules, *Waivers and Variances Rule* is approved the draft rule will be amended as shown in the presentation.
- b. There were no comments on section 3.

7 Measurement Point Definition Record

- a. The AESO presented the process for obtaining a new or amended MPDR contained in section 4 of the draft Rule, noting that section 4 is largely a continuation of the existing process for MPDRs that applies to transmission-connected generators and large microgeneration.
 - i. For subsection 4(1), the AESO proposes that the deadline for MPDR information is 30 days prior to the first day of the month in which the project is planned to energize because, for transmission-connections, the first day of the energization month is the effective date of the system access service contract. In addition, the AESO needs time to set up the measurement point in the AESO’s settlement system prior to energization. The information details will be made clear in a form for the MPDR application or listed in an information document.
 - ii. For subsection 4(3), complete information will allow the AESO to account for the proper measurement of the real and reactive energy. With some of the generation industry systems and now with the distribution side, the AESO has to link it back to the point of delivery (“POD”). The requirement to avoid deductive totalization in subsection 4(3) binds the AESO to not issue an MPDR that would place the market participant in territory prohibited by Measurement Canada.
 - iii. Subsection 4(4) is from the Measurement System Standard, but simplified to preserve flexibility.
- b. ATCO Electric asked who was expected to apply for the MPDR in the case of distributed generation (DG) because the participant that holds the MPDR is the generator owner, not the meter owner. ATCO Electric noted that the meter owner does not hold the Rate STS contract with the AESO.
 - i. The AESO responded that, per the applicability section, it will be the meter owner (i.e. DFO) that will apply for the MPDR. Based on the AESO’s understanding of DG, even if the generator owner holds/implements the MPDR, the DFO guides/instructs the generator owner on how to implement and operate it. The DFO does hold the Rate STS contract with the AESO, but the AESO is considering metering data, not the contract, so it would still be the DFO. The AESO needs to ensure that it is placing requirements on people who have authority, which is why technical requirements apply to the legal owner. If DFO owns the meter, it is tough to impose legal obligations on an entity that does not own the meter. The AESO tried to cover the possibility that the MPDR can be issued to a party different from the applicant in subsection 4(3). The AESO asked participants if there would be issues with this approach.

- ii. ATCO Electric clarified that typically there is just one bi-directional meter. ATCO Electric specified that in most cases the DFO installs the revenue meter and the DG owner applies for MPDR, so currently the DFO does not apply for MPDR. ATCO Electric noted that it is a different MPDR process between the distribution and transmission facilities where the TFO applies for MPDR.
 - iii. The AESO agreed with ATCO Electric that there is a bi-directional meter between the generator and distribution facilities, which the DFO owns. Generally, the TFO owns the meter between distribution and transmission facilities.
 - iv. The AESO agreed and further noted that the Rate STS contract is between transmission and distribution facilities, not between the generator and distribution facilities. So for the generator owner, the contract is on the DFO side. The AESO clarified it is referring to who owns the meter and provides data to the AESO.
- c. Fortis suggested that, like the federal government, the AESO could determine who has accountability for a meter through the contract registration number. This may be an eloquent way to see who has accountability for meter and measurement point. Fortis also noted that the federal government is trying to revise how they define “contractor” because it is becoming unclear in wholesale markets between DFOs and retailers. A contractor may not be the owner of the meter financially, but at the federal level, hold accountability for the accuracy and the requirements of that meter or meter installation. So it might be a simple way to identify accountability.
 - i. The AESO thanked Fortis for the suggestion, but expressed its general reluctance to tie ISO rule requirements to other legal instruments in case those other instruments change.
- d. Rodan noted that is it ok with the majority of section 4. Rodan asked if the information document has been released, and if not, when it will be available.
 - i. The AESO responded that an information document has not been posted. There is a rough version in the works based on the work of the 2017 technical working group, but the normal practice is to post IDs until after the Rule is approved. The AESO is currently focusing on the draft Rule and the AUC application.
 - ii. Rodan, referring to section 3, asked if information submitted by the owner to the AESO will be clearly outlined in the information document.
 - iii. The AESO confirmed that there will likely be a form for process efficiency. The AESO does not want to build the information requirements into the rule to maintain flexibility.
 - iv. Rodan recommended that terms and acronyms on forms should be defined since they have lots of market participants that question what they mean. Rodan further questioned if instrument transformer approval and meter approval information will be required and if these will be verified by the AESO. Rodan clarified that its question is based on experience with many sites where instrument transformers are either not approved or being operated at a tap which is unapproved. An approval process could be a good way to catch these issues.
 - v. The AESO replied that it does not ask for that information today, but can consider it. However, the AESO noted that these approvals are under federal regulations. It is not the AESO’s role to enforce federal regulations.
 - vi. Rodan added that a lack of enforcement provincially can lead to unfairness in the market. Rodan’s bids are based on a fully compliant system but there are others that get away with using unapproved instruments due to the lack of enforcement.

- vii. Fortis agreed with Rodan, noting that the industry needs to look at the E31 series of documents from Measurement Canada. As an example, Fortis referred to the options Measurement Canada has for interval data: there is legally-relevant interval data and non-legally-relevant interval data. The choice in the Alberta marketplace is which of the features does the AESO want to enable? If you are using non-legally-relevant interval data, you can produce time slice data (time of use) from interval data. If you want to derive demand from that interval data, then you must use legally-relevant interval data, verified to the cumulative registers of the meter on a daily basis. While Measurement Canada will allow meters to be approved to do one or the other, it is up to the utilities and the provincial marketplaces to determine how that is going to be applied. In part, the AUC is trying to do this with the Alberta Minimum Meter Guideline which sets minimums for the Alberta marketplace. The AESO needs to recognize, as a regulator, which features it wishes enabled or not enabled and it needs to decide which to apply when there is a choice from the federal regulator. There are a lot of rules to consider and a lot of organizations may not be fully aware of the interdependency between those rules.
- e. TransAlta asked how subsection 4(3)(c) applies if a new measurement point is added behind the fence in a net metering arrangement.
 - i. The AESO responded that it depends on purpose of the meter that is behind the fence. Is that meter being excluded from assets which are on the transmission side? And is that meter for settlement or dispatch compliance?
 - ii. TransAlta, in response, stated that it's not excluding the meter. The meter is measuring for purpose of tariff requirements for that net meter point for settlement. TransAlta added that it is trying to interpret what subsection 4(3)(c) means and the impacts.
 - iii. The AESO did not have a direct answer to TransAlta's question. The AESO explained that the intent of subsection 4(3)(c) is to harmonize with Measurement Canada. It is a requirement on the AESO that it cannot approve something that is contrary to Measurement Canada's prohibition against deductive totalization.
- f. The AESO, noting the discussion on MPDRs and meters owned by different parties, asked the representing DFOs (ENMAX, Fortis, EPCOR and ATCO Electric) to comment on the ownership of meters on their systems.
 - i. Fortis explained that, in most cases, Fortis provides that metering. The exception is if a generator owner provides its own metering for a DG.
 - ii. The AESO asked Fortis if Fortis is currently responsible for filing or applying for the MPDR with the AESO, or if the generator owner does it.
 - iii. Fortis answered that, in its case, it is the generator owner and who they contract with.
 - iv. The AESO explained that it assumed in section 4 that the party that applies for MPDR is also operating the metering. The AESO agreed to look at what clarifications are necessary here.
 - v. Fortis agreed that the AESO has to look at this in more depth.
 - vi. The AESO asked if Fortis was suggesting a more prescriptive approach that outlines different relationships.
 - vii. Fortis acknowledged that keeping it less complicated is great, but history has made it complicated.

- g The AESO encouraged attendees to think about what they would like to see clarified with respect to relationships.
 - i. AltaLink commented that it is looking for clarity on who is accountable vs. who owns. A lot seems to sit under the owner of asset, but the owner of the asset does not necessarily have the MPDR.
 - ii. Fortis noted that the federal government is looking at administrative penalties, which is a concern for DFOs and operators. Understanding ownership becomes important in this regard.
- h Rodan noted it does not see any reference to an information document in the proposed standard and asked if there is going to be a reference.
 - i. The AESO advised that it does not reference information documents in ISO rules because information documents are not legally binding. All information documents are on the AESO website on the same webpage as the rule.
- i Fortis identified that the definition of “revenue meter” refers to active energy and reactive energy at intervals as defined by the AESO, but in subsection 4(3)(b), metered energy, metered demand and metered apparent power are used. Fortis suggested amending subsection 4(3)(b) to be consistent with the definition of revenue meter.

8 Revenue Meter

- a The AESO explained that subsection 5(1) is to ensure the legal owner of the meter has necessary approval from Measurement Canada, and to avoid duplication with the federal framework. There were no questions or comments from participants.
- b The AESO explained that subsections 5(2) and 5(3) are largely carried over from the Measurement System Standard based on the recommendation of the 2017 technical working group.
- c Rodan advised that, because the draft Rule lacks specific requirements for revenue meters, market participants will be forced to go through Measurement Canada policy. This is already difficult, so some information should be included in the rule or in ID. On the topic of sealing, Rodan pointed out that Measurement Canada has sealing requirements but they only cover the physical meter. Rodan queried how important is it that tamper points like the instrument transformer secondary terminals are sealed?
 - i. The AESO highlighted that the vast majority of meters that the draft Rule applies to are medium to high voltage. Meters within a substation are subject to other security requirements. On the distribution side, the meters are commonly in an enclosure within the facility itself. Moreover, tampering with metering equipment is an offence under EGIA.
- d Rodan asked if the AESO would consider implementing rules for backup metering.
 - i. The AESO referred back to its cost effectiveness and principle. In the AESO's view, there is a trade-off between the cost of back up meters and the benefit. The draft Rule contains other sections on meter restoration. Also, dual meters should already have backup meters. It is not in the AESO's intent to limit backup meters to one single option.
 - ii. Rodan mentioned that, in its experience, the upfront cost of a backup meter is almost always less than seeking a dispensation or putting a temporary sealed meter. With respect to restoration, is that dispensation going to be handled primarily by the AESO and exclude Measurement Canada, or will a dispensation under E25 be required? It is

pretty comprehensive and it is a lot of internal labour. Putting a backup meter in would be a better solution.

- iii. The AESO noted that E25 is a federal requirement, so it is applicable to the entity accountable. The AESO asked if other participants had comments on the need to include backup meter requirement with the draft Rule.
 - iv. AltaLink questioned, based on record of failure rates, whether we need to “use an elephant to take out a mouse”? What is the reliability and what are the problems that we face?
 - v. Fortis identified that there are other jurisdictions with backup meters. Fortis asked Rodan if there is data supporting the need for backup meters. Managing back up meters can become costly quickly, so Fortis' initial thinking is that they are not needed. Ontario studies could be considered but there should be a discussion around this and the value.
 - vi. Rodan indicated it can provide Ontario data. Rodan further explained that, in its experience, it runs into issues with meter failures. When there is no backup in place Rodan has to get a dispensation from the AESO. Rodan would like clarity on if its client needs to seek a Measurement Canada dispensation in the event of an unsealed meter.
 - vii. ATCO Electric noted that unsealed meters are not allowed by Measurement Canada. It is possible to get a spare meter, so that when it goes down you can install it quickly. ATCO Electric has its own policy for backup meters (if over 5MW install a backup meter).
 - viii. Rodan agreed, but explained that a dispensation is the only solution in some situations.
 - ix. The AESO asked if demonstrating compliance with a backup meter requirement in an ISO rule would impose additional burden on legal owners.
- e Rodan flagged recorder requirements as another issue. There is nothing in AUC Rule 021, Measurement Canada or the draft Rule that defines the registers that the AESO wants to see in a meter for a bi-directional meter point. S-E-02 potentially allows for the use of a net register for bi-directional services, but if the AESO wants to have 4 separate channels it could create an issue.
- i. The AESO indicated that the Micro-generation Regulation specifies that bi-directional meters have two sets of registers, and also it is in the definition of bidirectional meter in the terminology section of S-E-02. Is this sufficiently clear for Rodan?
 - ii. Rodan, in referring to the relevant S-E-02 definition, explained that it can be interpreted as using a single net register.
 - iii. The AESO corrected its reference to S-E-05 section 4.
 - iv. Rodan expressed a general concern with how Measurement Canada rules are not always definitive, difficult to interpret, hard to follow and provide for grey area.
 - v. The AESO acknowledged Rodan's concern, but explained that the onus is on industry participants to understand and comply with Measurement Canada. The AESO's concern is getting boxed in by referencing specific Measurement Canada requirements in ISO rules. Where the AESO has a preference it can indicate it, but generally tries to avoid being overly prescriptive.
 - vi. Fortis mentioned that Measurement Canada has allowed the use of net registers as well as bi-directional registers. Fortis articulated that Alberta should be crystal clear about

having two separate registers. Fortis also advocated for a new distinction between legally relevant interval data and interval data. Section 5 should identify the requirements at the provincial level for frequency of the data, for example 5, 15, 30, 60 minutes. If it does not, we are limited in what we can do with that data outside the meter. In January 1, 2020 new requirements and after 2023 all meters must comply whereas grandfathering only goes up to 2024, so eventually every meter is going to be changed. There is an opportunity there to add clarity with this rule.

- f The AESO asked participants to summarize their priority items for specific revenue meter requirements.
- i. Fortis wants the AESO to define “legally relevant interval data” or “interval data”. If using “legally relevant interval data”, the AESO needs to define what is the “interval data” period (i.e. 5 min, 15 min).
 - ii. The AESO asked Fortis if interval data is already defined in Measurement Canada. The AESO mentioned that, if something is already defined, it typically won’t redefine it unless it needs something additional.
 - iii. Fortis explained that this is defined in S-E-11, and application of how it can be used. Fortis stressed that because the concept is so misunderstood, the rule should clearly identify that it will use Measurement Canada definitions.
 - iv. Fortis also asked the AESO to provide clarity on required registers for micro-generation, received and delivered for DG, SSG, and large or small micro-generation, and, if each interval meter is to have 2 or more channels, at what level (i.e. load) that should occur.
 - v. Rodan also asked for clarification on registers and if the AESO expectation is 4 channel, Rodan further noted there are new phases that require compensation that cannot be done inside a meter. Rodan asked if the AESO was going to define how those calculations are done, or are we going to rely on Measurement Canada loss policy?
 - vi. The AESO asked Rodan if the calculations defined in MPDR have been sufficiently clear in prescribing whether a separate register for bidirectional flow is required.
 - vii. Rodan agreed it is sufficient, but it still doesn’t tell you which registers to put in the meter.
 - viii. Fortis mentioned that Measurement Canada currently allows net registers, which allows net interval data or net values to be derived outside the meter.
 - ix. Rodan re-emphasized that the MPID is not sufficient for the ideal calculations. How it is done and where is not defined.
 - x. The AESO asked if compensation must be on the meter data system side? Is there any no-go on one option inside and outside of the meter and if there are implementation issues you have seen?
 - xi. Rodan responded that, the only option is a spreadsheet if the quadratics that cannot be handled by the meter. Rodan asked if this is allowable and will it be defined.
 - xii. TransAlta referenced the AESO's intention to allow flexibility so entities can choose what to do.
 - xiii. The AESO indicated that has relied heavily on the recommendations from the 2017 technical working group.

9 Measurement Transformers

- a The AESO presented section 6 of the draft Rule.
- b Rodan asked if situations where people are sharing measurement transformers were going to be grandfathered in the draft Rule.
 - i. The AESO asked Rodan about what the extent of meters sharing CTs is, and if Rodan has data or analysis on the topic.
 - ii. Rodan responded that is significant and indicated that it could provide some examples.
- c Rodan recommended that there should be a requirement about ongoing maintenance or, upon energization, there should be commissioning process for instruments.
 - i. The AESO mentioned subsections 7 and 8 of the draft Rule cover verification and in-situ testing and reference other ISO rules that pertain to commissioning of transmission and distribution-connected generators. The AESO asked participants if they see the need to submit metering information to the AESO for assets over 5MW.
 - ii. Rodan indicated that it submits a single line diagram for its clients.
 - iii. Fortis mentioned a Measurement Canada bulletin that gives everyone a pass right now. However, Measurement Canada is looking to require the accreditation of organization for commissioning of sites with CTs and PTs, as well as for field inspection services. Frequency of inspections have not yet been determined. Fortis commented that the federal government believes they have a legal obligation to inspect, as the entire installation is considered a meter.
 - iv. The AESO pointed out that subsection 7(3) is referring to the entire measurement system, including the data system.
 - v. Rodan questioned whether subsection 7(3) was placed under the right category within the rule, but generally agreed that subsection 7(3) seemed valid as long as the description includes instrument transformers. Rodan asked if the AESO would put a plan for sites that have unapproved transformers?
 - vi. The AESO asked all participants if such a plan was needed.
 - vii. Fortis commented that dispensated sites go back many years. Dispensation with Measurement Canada, which was ultimately dealt with at AESO level.
 - viii. The AESO explained the purpose of the measurement data is for the settlement process so if there are any changes we will have to readjust.

10 Metering Data Services

- a The AESO presented subsections 7(1), (2) and (3), noting that some of these topics were discussed earlier. It is the intent of the AESO to avoid prescriptive methodology.
- b TransAlta mentioned that the “reasonableness” threshold in subsection 7(3) could be arbitrary. The issue being that the AESO can come back and deem something unreasonable and the market participant is then out of compliance.
 - i. The AESO acknowledged TransAlta’s comment and agreed to revisit the language in subsection 7(3).

11 Revenue Meter Testing and Reporting

- a The AESO solicited input on the options for subsection 8. Specifically, the methodology for determining the MW classes for in-situ testing and what happens if a measurement point changes between MW classes.
- b Rodan provided support for eliminating 6-month inspection frequency. Very large sites should be looked at annually as the cost is negligible compared to generation output. Rodan does not believe the 10 corrections found by the AESO is a good representation because of how testing is done now, there could be measurement drift in instrument transformers that is not caught. When tests are done it is quite rare that you do hot stick primary reading for current due to safety restrictions and you can only do secondary testing. If the way you validate system accuracy is to compare against secondary system, and in some instances that is the same, you can have issues without even knowing. There are issues with testing now and upon site energization commissioning. With respect to recommended frequencies; if we want to stay with 2 and 4 years Rodan is ok with removing, and keeping 10-50 MW. Before 1 MW it would not apply very often, and meter had to be tested as per Measurement Canada. If there is a problem with the measurement, settlement correction becomes more difficult as time passes. Safety issues and tampering, corrosion and water damage can be found in in-situ testing.
 - i. TransAlta asked Rodan if the issues described were related to the size of unit.
 - ii. Rodan responded “no”.
- c The AESO asked participants if anything has changed since the 2017 technical working group recommendation; specifically, if participants now support more frequent testing intervals.
 - i. ATCO Electric compared the tables and noted that Rodan’s recommendation requires more frequent testing. ATCO Electric suggested the 2017 technical working group’s recommendation as the minimum requirement, noting that there is nothing preventing the meter owner to test more frequently if they need to.
 - ii. TransAlta stated that it did not support a more stringent requirement, but mentioned that it is exposed to the impacts of the revenue meters not being tested and are affected by the side effects. If it wants to do more testing, the optionality exists.
 - iii. Fortis agreed that the minimum standard should be set by the rule. Fortis articulated that testing needs to look closely at Measurement Canada changes: from January 1, 2020 to 2023, Measurement Canada is expecting each site to be inspected, which may or may not be a physical in-situ test. Fortis recommended considering similar criteria to E31 under validation requirements for “grandfathered installations”. There is a transition period between now and 2023 and Measurement Canada had said that, until you upgrade your meters, you will be under this grandfather clause that has a frequency. Fortis emphasized that the rule should address the transition period and the move forward period and the requirement has to be defined by the meters type approved (whether it is S-E-02, SS06 vs PSE18 and PSE19). Fortis suggested having the reduced frequency for the new standard of meters as we have defined and then default over that transition period to what Measurement Canada is proposing, which is forcing a review of every installation.
 - iv. The AESO noted that Measurement Canada is requiring inspection of meters starting Jan 2021, so some of these issues can be caught by complying with that.
 - v. It also urged attendees to please keep in mind compliance requirements, if there is a suspected non-compliance we have to send it to the MSA. Other regulatory rules are

requiring you to inspect your meters, so the AESO is trying not to put more regulatory burden on market participants by not having them be in contravention of both requirements or incurring duplicate penalties.

- vi. EPC mentioned that it has changed its testing procedure to test the primary to secondary accuracy, with the caveat that some sites cannot be done for safety reasons. However, those sites are fewer compared to the overall population.
 - vii. AltaLink asked Rodan if the concern has more to do with instrument transformers and less to do with cycle itself.
 - viii. Rodan responded that its concern is with measurement accuracy and integrity. Rodan questioned whether the testing intervals should be for convenience or for integrity. Rodan asked what Measurement Canada standard covers less than 5MW.
 - ix. ATCO Electric noted Measurement Canada doesn't have any rule regarding the retest frequency, but the 6 years mentioned there are regarding verification period. Typically, if a meter is not part of a group, it probably has to be pulled out and re-verified. Every time you pull a meter and verify it you have to test it again.
 - x. Rodan noted 6 years is a brand new meter or one that is within 12 months of purchase for their pool, but every subsequent reseal after that on a refurbished meter is 4 years.
 - xi. ATCO Electric responded that if it is under 4 years and you pull out the meter, you are required to retest. Essentially if you retest it every 4 years, there is no issue with the schedule.
 - xii. Fortis added that depending on the device you use, the seal period is 6 or 10 years, typically many of this class of metering fall within the 6 year period for reseal. We are also implying that when you do a site check you do in-situ check so we need to be careful and clear on how we are testing because we may not get any value. How far we want to go from a diligence point of view is up for discussion.
 - xiii. The AESO pointed out that, under subsection 8(3), it can ask the legal owner at any time to test and the legal owner is obligated to report to the AESO within 30 days.
 - xiv. EPC noted that, on the topic of commissioning of metering installation, there is a requirement to test the installation to ensure that all components are correct and valid, but confirmed there is no prescribed way for how this is done. EPC expressed its support for the proposed testing frequency as minimum requirements.
- d EPC generally commented that, ultimately all meters are used for billing settlement within the AESO, and these meters need to be compliant with Measurement Canada. Because Measurement Canada regulations might change, referencing as opposed to writing them into the new standard is a better approach.
- e EPC asked Rodan if a backup meter is a spare meter or is it a wired-in second meter, or is it a standby meter wired in?
- i. Rodan explained this would be a wired-in meter that does not have to be connected but it would share instruments with the primary meter.
- f EPC mentioned that measurement integrity is most likely compromised when the site is changed or touched so Measurement Canada requires testing whenever a site is changed, including the components and the meter. EPC asked Rodan whether this testing satisfies the need to look at site to ensure measurement integrity.

- i. Rodan responded that it would upon the change, but not for ongoing operation.

- g The AESO went on to explain the methodology options for determining the MW class. It is not clear if the methodology in the Measurement System Standard used all hours in the year or not. The AESO proposed to use all 8760 hours to make the calculation simple. Each generator and load has its own measurement point and since the MW class is calculated for each measurement point, they will be calculated and paired separately. Rodan proposed to strip out zero MW hours and only use non-zero MW hours. For solar plants, this would mean stripping out half a year
 - i. Rodan agreed that there is nothing today that tells you how to use calculate MW class, rather just how to report it annually. Rodan explained that the MW flowing through meter system is the reasoning for ignoring non-zero MW intervals. For example, if you have a 100 MW plant that puts out a steady 100 MW when it generates and it is running for 1/10th of the year, should it be in category of 100 MW or would you divide that and put it in the 10 MW class? Should a meter point with a higher impact on the grid when it is operational be tested more frequently or should it be based on the average throughout the year? This is not clearly defined in the current standard.
 - ii. ATCO Electric indicated that it ignores zero MW intervals, but would have to confirm with its data management system.
 - iii. The AESO asked other participants how they are currently calculating MW class, noting that it would be valuable to understand what the current practices and expectations are across the board.
 - iv. Rodan noted that if zero MW hours are included in the calculation, it is possible that a plant could fall under a different MW class each year depending on whether it is turned off. Rodan articulated that if a plant has capability to do 70 hours, it should be classified as that regardless of how many hours with MW it is running.

- h The AESO asked participants how measurement points with a changing average should be treated. What are the current practices for defining the MW classes and what are the compliance considerations?
 - i. Rodan stated that sometimes a few meter points a year will change classes and make the meter point overdue and we test it as soon as possible at the new frequency. Will the timeframe to calculate MW classes be defined? Is it a Nov – Nov or a Jan - Dec calculation?
 - ii. The AESO explained it is currently determining the data set being used to do that test. It is looking for input from industry. Is it influenced by business cycle, should there be a standard time frame, other circumstances that require it to be different for different entities?
 - iii. Rodan has no preference. Whatever the AESO says is what we will use. Thinking Nov – Nov would be best to get quotes done for next year.
 - iv. The AESO asked if everyone is currently different or are they standardized for all their clients?
 - v. Rodan answered currently it is whenever we can link it.
 - vi. The AESO asked if anyone would not support Nov – Nov for data set that goes to methodology.

- vii. ATCO Electric replied that if you impose the date, then some utilities might have to change the system. Someone else may take different timeframe than what Rodan does now. Cautious if we agree there may be some system changes.
 - viii. TransAlta asked how the AESO intends to deal with this as compliance issue. TransAlta would say canvassing is what they are using now, and then get a sense of what most people are gravitating to. Single year average you will always have point of potentially crossing to another class. Trying to minimize from year to year volatility would be helpful.
 - ix. EPC noted the interval could be a rolling 12 month to calculate the MW class to determine the class rating.
- i The AESO moved on to Section 8(2), on providing results of revenue meter testing. If it is plus/minus 3% which is a carryover of the requirement. Any questions/comments?
- i. Rodan noted that the way this is written, owners are only expected to provide test results to the AESO for a failure. For enforcement, how can you guarantee someone is carrying out in-situ test if they are not required to provide evidence or test form? Is there going to be any test procedures or requirements at all or will this be left to discretion? If no requirement, how can you ensure they are actually performing those services and tests to AESO expectations?
 - ii. The AESO responded that subsection 8(1), which will be the requirement to perform in-situ testing in accordance with a particular interval, will reflect this. As far as the actual reporting of the testing, the AESO only needs to know if the results are not clean. The AESO explained that the 2017 working group looked at what should stay and what should go. There was an agreement to remove the particular appendix and not place it in the rule, but if the thinking has changed the AESO is open to making it more prescriptive and place legal obligations on people to conduct testing in accordance with a certain process. The AESO wants an understanding on how things are happening right now and how it works within compliance with AESO rules.
 - iii. Rodan asked if there are any existing Measurement Canada standards that the working group knows about regarding in-situ test all in one place.
 - iv. Fortis explained that not specifically for Measurement Canada, but they have field procedures for their own staff that can be used as a guide but do not need to be prescriptive. Measurement Canada, is looking to revamp their processes, if organizations will be accredited then equipment has to be certified and traceable. Right now Measurement Canada does not require organizations to self-report if exceeding plus/minus 3%. If reported or published, then Measurement Canada would have an obligation to review and consider applying administrative penalties. Is it not legal under the Federal Act to have facilities operating outside of plus/minus 3%. The AESO might want to look at this from a legal perspective between provincial and federal rules and ask if this disclosure creates some legal issue around that reporting. If so, how would it be approached?
 - v. The AESO noted it definitely wants to harmonize with Measurement Canada and will look at Measurement Canada's standards. It then presented requirement 8(3) with respect to unusual data reporting requirements which will not be used on a routine basis, and there were no comments on this subsection.

12 Measurement Data Corrections

- a The AESO explained and presented the rationale for subsections 9(1) through 9(4). Currently these corrections are not in the Measurement System Standard. However, the

AESO does have a routine process for the meter owner, or MDM acting on their behalf, to submit data corrections. The purpose of putting this in the draft Rule is to formalize the process. It is a two-step process where right now the data correction request comes in to the AESO, the AESO verifies the data and once it is vetted it can be uploaded into CDMS. This is such that the AESO can verify data corrections against either prior data (prior settlement period) or source data such as SCADA. The AESO does not intend to change the current process or forms that are being used.

- b TransAlta asked if subsection 9(4) is repetitive of subsection 9(2).
 - i. The AESO explained this is more on the submission process. Subsection 9(2) is for where a summary of correction is provided. Subsection 9(4) is the actual submission. There is a vetting that goes on first, and then the market participant can enter the correction into the system once the vetting is complete. Essentially subsection 9(2) is the summary and subsection 9(4) is DSM.

- c ATCO Electric asked if there is a timeframe for the error, or is it once you find it? Under the settlement process if it is before the final you don't have to do any paperwork. If you find an error, you just process the data and publish it.
 - i. The AESO noted that currently if the error is found just before settlement, it must be fixed. If the data is already published (after settlement), then you need to submit a correction form and the AESO needs to validate that.
 - ii. TransAlta is concerned that this is too onerous on the MDM because if you have lots of feeder points you may not get the data in time as there is daily, monthly and final data. Sometimes you don't get the data by the monthly deadline because communication or other issues.
 - iii. The AESO agreed and explained that the original wording referred to final settlement, if you discover an error after settlement, but the working group started exploring what happens if you discover errors at any time. If this does create more onus on market participants, the AESO is sympathetic to that, but it did qualify in subsection 9(1) that it is triggered only when an error is discovered.
 - iv. TransAlta confirmed this is not related to a change in data, rather a metering error.
 - v. The AESO confirmed this is the intent. If you have data error prior to settlement, you can submit it without any approval from the AESO.

- d ENMAX asked how the process works when you are submitting the data and there is no error, but meter communication failure has caused the data not to be submitted to the AESO for 3-4 weeks, but it is still within the month. Further, if final is within 3-4 months, if it is still within that timeframe?
 - i. The AESO confirmed you don't need to submit the form to the AESO if it is within the one month before the settlement. The AESO explained its current procedure is that after initial settlement, you have to submit the form. The intent is not to cover late data just to cover errors when they are discovered.

- e Fortis requested confirmation that the AESO wants the form submitted after initial settlement, which is basically 7 days.
 - i. The AESO confirmed it is 7 days after that month. If you missed the month you have 7 days. This aligns with current practice.

- ii. Fortis thought the form was to be submitted after final settlement, which is 4 months.
 - iii. The AESO explained its intent is whenever the error is noticed; notify AESO as soon as practicable. It didn't want to put any hard and fast requirements.
- f Fortis asked if the AESO considers an estimate interval an error. Because this information will be replaced when you get actual.
 - i. The AESO confirmed it does not. If the actual data replaces the estimate, then it is not an error. If the error is after initial settlement, that is when you need to submit the actual form. The AESO further asked if there will be support of this submission requirement applying post certain settlement periods (i.e. post-initial, post-final).
- g Rodan asked if this is already covered under AUC Rule 021.
 - i. The AESO explained this is in support of PFAM. So the question is more on whether to report before or after initial settlement. The data coming in already has initial settlement and if you submit again, load compliance will want to know that happens because they can't see the different versions, but they want to know. This is why you need to submit after the initial settlement.
 - ii. ATCO Electric noted it believes this is a redundant process because the AESO already has the initial data and at the end they get the actual data so do you need a form anyway? From a metering perspective you have actual data to replace the estimate. Unless the AESO notices that the data is erroneous.
 - iii. The AESO asked how it would know that this is an estimate and not incorrect data. However, if you have a form to explain an error, the AESO can tell the difference.
 - iv. ATCO Electric noted that in the file itself there is a field for an actual measure, so if there is an estimate and replacing by actual, which should be the end of it.
 - v. TransAlta further explained that part of the AESO's form is submitting a reason for error, and when an estimate is submitted it isn't an error.
 - vi. The AESO confirmed that errors in estimates are not meant to be caught on this. This is after submitting the actual data. The AESO will take the wording away to ensure it is clear.

13 Restoration

- a The AESO presented the proposed draft subsection 10 on restoration. The draft was discussed in June 2017 with the working group. The bulk of the requirements are a continuation of the existing Measurement System Standard. This refers to the owner of the revenue meter becoming aware of the failure of the revenue metering system, which covers cities all the way to data system, and notify the AESO in writing. Subsection 10(2) is on timing. Currently the standard is by business days of being aware of the failure. In the 2017 working group meeting, the discussion was to move this to 30 calendar days or 30 business days. Currently the AESO proposes a 30 calendar day timeline which would allow for a more complete investigation of the failure. Also, the choice of calendar days over business days was made because revenue meters read 24hrs a day, beyond business hours.
- b TransAlta noted a drafting item. There are now compliance obligations that the AESO is going to amend the restoration plan in a manner that will resolve that failure. Is it the real requirement that the person that noted they have a revenue system issue notifies the

AESO and specifies what the restoration plan is and come back and restore that system to make sure it is operating correctly. They help for understanding the process, but as a rule drafting component, it seems like it is more than what might be needed.

- i. The AESO understands there are meters that have lead time and that is where the restoration plan comes in. That is also where the agreement between the AESO and the meter owner to use an unsealed meter comes in.
 - ii. TransAlta just noted these are strange compliance obligations to impose on the AESO and the market participant. The market participant identifies that the system has failed; they are notifying the AESO and explaining what the restoration plan is. Obviously there is a process that is invoked by the AESO to ensure the timeframe is reasonable, but the AESO is now committing itself to directing the market participants on assigning a reasonable amount of time; but the end outcome you are trying to target is that the legal owner has to restore that revenue system.
 - iii. The AESO appreciates TransAlta's comment. This provision is about the process and understanding the process, but there may be a way to simplify the language.
- c Fortis noted, regarding the comment made with respect to permission to use a meter without a seal, this is Measurement Canada jurisdiction, which would make the meter owner non-compliant. Regarding data corrections, there are two kinds of data: actual data available because you have a metering system working, or you have estimated data available. Restoration is covered within AUC Rule 021 around how the data correction is managed. We need good clarity around the meter data corrections, and when those are necessary. A suggestion when looking at corrections over a significant threshold, maybe then it is more of a reporting mechanism to explain why there is such a significant change as opposed to trying to monitor the correction.
- i. The AESO agrees it is important to know what the rationale is and that is the rationale behind the reporting of subsection 9. What causes the correction?
 - ii. Fortis further noted that AUC Rule 021 has TAA transaction for adjustments done on system level. The proposed ISO rule does not have a reason code in there on normal sites within AUC Rule 021. The RSA is done for residential farms, etc., but on the system level TAA is done. Maybe it is a matter of changing AUC Rule 021 and putting a reason code transaction.
 - iii. The AESO noted that is a good suggestion. It reverted back to the many regulatory tools that apply to metering and AUC Rule 021 is one of them, and this is something to consider. The AESO repeated the intent of section 10 of AUC Rule 021 doesn't address how long you have to estimate the meter. The intent here is to ensure the estimate is as short as possible. The AESO expects the failure to be fixed as soon as possible. Here we have all the timelines to make sure the meter is restored as soon as possible.

14 Information Document (ID)

- a The AESO presented a list of items that it flagged for an accompanying ID, but acknowledged that the discussion on an ID may be premature because it is dependent on the content of the final, approved rule.
- b Heartland asked if the AESO would commit to releasing an ID before filing the rule with the AUC. Heartland recommended writing the intent into the rule because down the line, people forget what the intent is and it will change or get made up.

- i. The AESO explained that it endeavours to draft rules that can stand on their own and don't require IDs. The AESO also referred to the new AUC Rule 017 where the onus is on the AESO to satisfy the legal test under the EUA, requiring it to provide a lot more detail about the rules in its applications to the Commission. The application content, as well as stakeholder presentations, will likely form the basis for the ID. This also ensures that the AESO is not expending resources on IDs for rules that haven't been approved.
 - ii. Heartland's general concern is that the ID ends up becoming the record going forward, and not the presentation
- c. Rodan expressed similar concern for information getting lost if it is not in the rule. In Rodan's view, third party service providers should be mentioned in the rule. Rodan asked the question: the AESO is in charge of the grid, so if it has a view to what the best practice is, why doesn't the AESO make it the requirement for every company? Rodan stated that it appeared like the AESO is trading convenience for reliability.
 - i. The AESO explained the rule needs to consider fairness for all market participants. Best practices for one entity may not be the same for another. This is why the rule aims to set out minimum requirements for all. Also, the AESO has to weigh and balance a lot of interests and configurations and the province is quite unique in this regard. Whatever the AESO writes in rules can directly impact the ratepayer.
 - ii. Rodan stated that if it is in the rule then it can be regulated but if something just a guideline a person can hire anyone to do it and you have no control over the knowledge, process, etc. This impacts quality of what you receive.
 - iii. The AESO referred to the regulatory regime at large and how, for example, there are other registration and accreditation programs. There is a registration system with the AUC because there is a meter data manager identification defined in the DCM DIM transactions.
 - iv. Rodan noted that AUC Rule 021 refers to meter service provider, but does explain what it is. AUC Rule 021 goes into more detail on meter data managers. Rodan mentioned that the majority of owners of sites it works with today are using a meter service provider. Rodan questioned why the rule wouldn't reflect how the majority of this market operates.
 - v. TransAlta asked Rodan whether Rodan would take on the liability for rule compliance if permitted by the regulation. If that is the case, then TransAlta would support it.
 - vi. Rodan, noting that the purpose of its meter service provider program is to take over regulatory burden for operators, confirmed that it would take on the liability.
- d. The AESO summarized the discussion on the applicability of the rule requirements; specifically, more thought needs to be given to whether something should apply to the owner of equipment versus the entity responsible for carrying out the particular process or function. The AESO asked for last thoughts on leaving it up to freedom of contract and commercial parties to do as they please, or if the preference is for the AESO to take on an oversight role of meter data managers. In regards to the latter, the AESO noted its statutory mandate.
 - i. TransAlta questioned what would happen if a provider sold services for cheap and then ended up having a lot of compliance violations. It could see how some would have issues taking over such liability.
 - ii. ATCO Electric highlighted that, under the proposed applicability, if the meter owner contracts services then the meter owner is liable and liability has to be written in contract.

This is the same as billing in a substation. It is the owner's obligation to ensure they are compliant.

- e Rodan, in reference to subsection 7, asked why the meter service provider definition is included in the rule and not meter data manager.
 - i. The AESO clarified that the reference to "Meter Data Services" in the heading of subsection 7 was not intended to convey that the requirements in subsection 7 must be performed by an MDM or MSP. Further, MDM and MSP are AUC Rule 021 terms.

15 Definitions

- a The AESO requested feedback on the proposed new and amended definitions, noting the extensive discussion that already occurred for "revenue meter".
- b "measurement point definition record": no comments.
- c "measurement point":
 - i. ATCO Electric noted that the wording of "algorithm manipulation" may not align with Measurement Canada. The AESO agreed and proposed the wording of "adjustment".
 - ii. Heartland generally commented that it is not supportive of definitions within definitions. Heartland understands the need to be flexible but, from the market participant perspective, ill-defined terms are difficult to deal with.
- d "metering point":
 - i. The AESO acknowledged that the word "manipulation" could be revised to "adjustment".
- e "revenue metering system": no comments.
- f "revenue meter":
 - i. Rodan asked if the definition was necessary, given Measurement Canada's definition.
 - ii. The AESO explained that the definition for ISO rules is narrower as it is qualified by intervals and the meters being for purpose of financial settlement with AESO. In this regard, Measurement Canada's broad definition did not work.
 - iii. Rodan emphasized that, without a grandfathering clause, people will have to install a new CT because they cannot share a CT core anymore. This will be costly.
- g "metered demand":
 - i. Fortis said it struggled with the definition "averaged is over 15 minute period". When looking at demand, from a measurement point of view, there is a "block demand" available and a "sliding block demand" available. Both are not necessarily an average, so we need to be consistent with choices between available "sliding block" and "block demand". Average is not recognized as legal, so definition should clarify "block" or "sliding block".
 - ii. The AESO will consult with its tariff team.
- h "metered energy": The AESO explained it that is it proposing to remove "point of delivery" and "supply" because those are transmission concepts. No comments.
- i "metering equipment": no comments

16 Next Steps

- a The AESO to circulate draft meeting notes to attendees for comment.
- b The AESO will finalize the meeting notes following receipt of comments.
- c The AESO will put out a comment matrix to request additional information and seek feedback to specific questions based on today's discussion.
- d The AESO thanked attendees for their valuable input and feedback.