Decision **25848-D01-2020**

AUC
Alberta Utilities Commission

Alberta Electric System Operator

Stage 2 Review and Variance of Decision 22942-D02-2019 Adjusted Metering Practice and Substation Fraction Methodology

December 23, 2020

Alberta Utilities Commission
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
Proceeding 25848

December 23, 2020

Published by the:
Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

Telephone: 310-4AUC (310-4282 in Alberta)
1-833-511-4AUC (1-833-511-4282 outside Alberta)
Email: info@auc.ab.ca
Website: www.auc.ab.ca

Contents

List of figures

Alberta Electric System Operator
Stage 2 Review and Variance of Decision 22942-D02-2019
Adjusted Metering Practice and Substation Fraction Methodology

Decision 25848-D01-2020
Proceeding 25848

1 Decision summary

1. In this decision, the Alberta Utilities Commission considers whether to confirm, rescind, or vary specific findings and directions in Decision 22942-D02-2019 (the Decision)[1] related to the Alberta Electric System Operator's (AESO) substation fraction methodology and the implementation of the adjusted metering practice.

2. For the reasons that follow, the Stage 2 panel varies the Decision and:

- Approves the AESO's proposal to set the substation fraction equal to one on a prospective basis.
- Directs the AESO to recalculate construction contribution decisions back to December 1, 2015, in accordance with the findings in this decision.
- Identifies principles by which a solution can be brought to distribution facility owner (DFO) tariffs, both on a prospective basis and on a retroactive basis, as specifically articulated in this decision.
- Directs DFOs to file reports by March 31, 2021, setting out the details of all resolutions and outstanding disputes pertaining to distribution-connected generation (DCG) flow-through matters.
- Finds that grandfathering the AESO's adjusted metering practice is not necessary, and directs the AESO to proceed with its implementation in accordance with the findings in this decision.
- Confirms the hearing panel's findings on the interpretation of sections 28 and 47 of the *Transmission Regulation*.

3. Except as required to give effect to the Stage 2 panel's findings and directions, the Stage 2 panel confirms the Decision as it relates to the issues raised in the proceeding.

4. The AESO is directed to file a compliance filing to affect the Stage 2 panel's findings and directions in this decision by January 11, 2021.

[1] Decision 22942-D02-2019: Alberta Electric System Operator, 2018 ISO Tariff Application, Proceeding 22942, September 22, 2019.

2 Introduction and procedural background

5. In the Decision, issued on September 22, 2019, the Commission approved the AESO's proposed adjusted metering practice and continued use of the substation fraction methodology to allocate the costs of local interconnection facilities that may have joint use as part of the 2018 Independent System Operator (ISO) tariff. A decision on the associated compliance filing was issued on November 30, 2020.[2]

6. On November 21, 2019, the Commission received review and variance (R&V) applications from FortisAlberta Inc.[3] and the Community Generation Working Group[4] (Canadian Solar Industries Association, First Nations Power Authority, and the Alberta Community and Co-operative Association, collectively, the CGWG), related to the findings in the Decision on the AESO's adjusted metering practice. The Commission ruled that it would hear the R&V applications together and issue a single decision.[5]

7. Following the release of the Decision, the Commission also received a complaint from BluEarth Renewables Inc. regarding a change to Fortis's practices for allocating costs from the AESO based on the substation fraction methodology.[6] [7] The complaint proceeding was suspended pending a resolution of the two related R&V applications.

8. On December 16, 2019, the AESO filed a submission proposing to facilitate one or more technical meetings to develop a joint proposal on the need for potential changes to the substation fraction methodology as a result of the approved AESO adjusted metering practice.

9. The Commission approved the AESO's request and suspended the R&V proceedings on January 15, 2020.[8] Four technical meetings were held by the AESO between February 27, 2020, and June 25, 2020. Participating stakeholders included DFOs, DCGs, other interested parties and Commission staff.

10. In a July 13, 2020, letter,[9] the Commission identified potential inconsistencies between the adjusted metering practice included in the AESO 2018 tariff compliance filing and the anticipated change in the substation fraction methodology resulting from the technical meetings. Based on parties' submissions, the Commission considered that an alternative to the approved substation fraction methodology could resolve the issues related to the implementation of the adjusted metering practice that served as the basis for the R&V applications and the BluEarth complaint. The Commission determined that the path forward should not further delay the

[2] Decision 25175-D02-2020: Alberta Electric System Operator, 2018 ISO Tariff Compliance Filing, Proceeding 25175, November 30, 2020.
[3] Proceeding 25102, FortisAlberta Inc. Review & Variance of Decision 22942-D02-2019.
[4] Proceeding 25101, Review & Variance Application of AUC Decision 22942-D02-2019.
[5] Proceeding 25101, Exhibit 25101-X0014, Process schedule and ruling on cost eligibility, December 17, 2019, paragraph 13; Proceeding 25102, Exhibit 25102-X0009, Process schedule, December 17, 2019, paragraph 5.
[6] Proceeding 25058, BluEarth Renewables Inc. - Complaint against FortisAlberta Inc.
[7] Proceeding 25058, Exhibit 25058-X0005, BluEarth Complaint re Fortis Letter, paragraphs 3-10.
[8] Proceeding 25101, Exhibit 25101-X0037; and Proceeding 25102, Exhibit 25102-X0031, AUC ruling on AESO technical meeting, January 15, 2020.
[9] Proceeding 25175, Exhibit 25175-X0090; Proceeding 25102, Exhibit 25102-X0033; Proceeding 25101, Exhibit 25101-X0039; Proceeding 25058, Exhibit 25058-X0035: AUC letter - Process proposal for proceedings considering ISO tariff provisions related to DCG, July 13, 2020.

AESO's compliance application nor the resolution of the issues related to the AESO's adjusted metering practice and its substation fraction methodology.

11. On September 1, 2020, the Commission issued Decision 25101-D01-2020 and Decision 25102-D01-2020, granting a review of the Decision[10] and establishing the scope of the current Stage 2 variance proceeding.[11] Also on September 1, 2020, in a ruling on process designating the current proceeding as the Stage 2 variance proceeding, the Commission indicated that it would pre-register all parties involved in the related proceedings in the current proceeding, and that any other parties should register their statements of intent to participate (SIPs) by September 4, 2020.[12]

12. The Commission's established process provided interested parties with the opportunity to file submissions by September 15, 2020, and response submissions by September 29, 2020. The Commission considers that the record of this proceeding closed on September 29, 2020, the date on which response submissions from parties were received.

13. This decision addresses the requests made in the R&V applications, as well as the issues raised in the complaint from BluEarth related to the findings in the Decision on the AESO's adjusted metering practice.

14. In this decision, the members of the Commission panel who authored the Decision will be referred to as the hearing panel; the members of the Commission panel who authored Decision 25101-D01-2020 and Decision 25102-D01-2020 will be referred to as the Stage 1 panel; and the members of the Commission panel considering the current second stage R&V submissions will be referred to as the Stage 2 panel.

15. In reaching the determinations in this decision, the Stage 2 panel has reviewed the pertinent portions of the Decision; Decision 25101-D01-2020 and Decision 25102-D01-2020; Decision 25175-D02-2020; relevant materials comprising the record of the current proceeding; Proceeding 22942 (the original proceeding); Proceeding 25175 (the compliance to the original proceeding); Proceeding 25058 (the complaint filed by BluEarth); and proceedings 25101 and 25102. Accordingly, references in this decision to specific parts of a record are intended to assist the reader in understanding the Stage 2 panel's reasoning relating to a particular matter and should not be taken as an indication that the Stage 2 panel did not consider all relevant portions of the several records with respect to the matter.

3 The substation fraction methodology

16. The Stage 1 panel identified concerns with the ongoing risk to DCGs for future DFO substation upgrade costs passed on through the substation fraction methodology, because DCGs have no control over the timing of substation upgrades nor their costs, other than upgrades for which the DCGs are responsible, and which have been taken into account in their investment

[10] Decision 25101-D01-2020 and Decision 25102-D01-2020: Community Generation Working Group and FortisAlberta Inc., Decision on Preliminary Question, Application for Review of Decision 22942-D02-2019, Alberta Electric System Operator, 2018 Independent System Operator Tariff, September 1, 2020.
[11] Decision 25101-D01-2020 and Decision 25102-D01-2020, Appendix 2 - Scope.
[12] Exhibit 25848-X0003, AUC letter – Ruling on process for proceedings considering ISO tariff provisions related to DCG, September 1, 2020.

decisions. The Stage 1 panel held that this was an issue within the scope of the variance proceeding in consideration of feedback from parties that this risk could be dealt with through adjustments to the substation fraction.[13]

17. This section of the decision is organized as follows:

(i) Background of the current Rate Supply Transmission Service (Rate STS) and Rate Demand Transmission Service (Rate DTS).

(ii) Sections 28 and 47 of the *Transmission Regulation*.

(iii) The application of the substation fraction methodology to new projects.

(iv) The application of the substation fraction methodology to existing projects.

(v) Principles for future ISO tariffs.

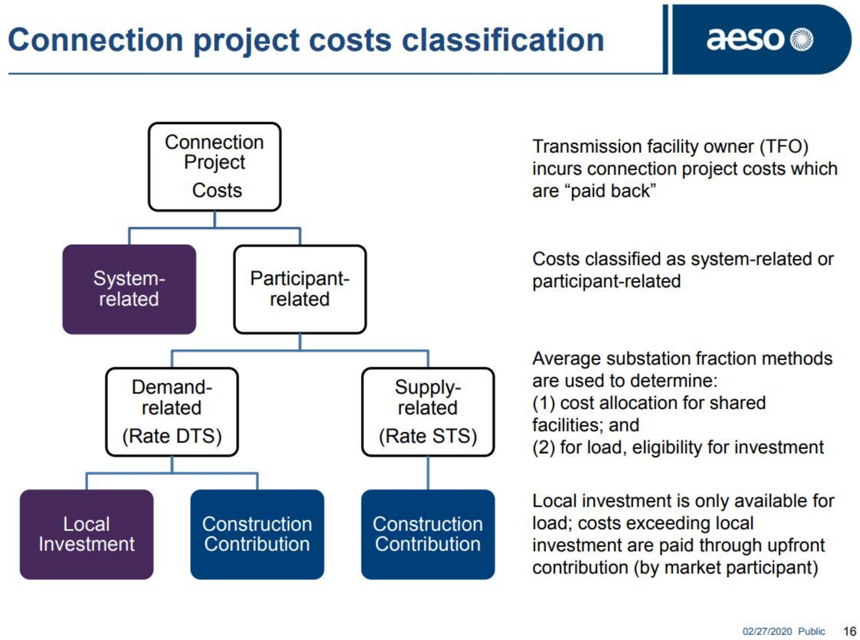
(vi) Clarification of outstanding obligations from Proceeding 25058.

3.1 Background of Rate STS and Rate DTS

18. The AESO's tariff classifies all costs of a connection project as either participant-related or system-related.[14] This classification determines who will be responsible for paying the initial costs of a connection project. During its first technical session,[15] the AESO produced the following graphic, which illustrates the methodology it uses when it evaluates connection projects.

13 Exhibit 25848-X0004, Appendix A – Scope of Proceeding 25848, page 11.
14 ISO tariff subsection 4.2(1) in the 2018 ISO tariff as approved in Decision 25175-D02-2020.
15 The first technical session was held on February 27, 2020.

Figure 1. AESO connection project costs classification



19. As shown in Figure 1, the AESO allocates the costs of a participant-related connection project, using the substation fraction methodology, among the participants receiving system access service (SAS) through those shared facilities.[16] The methodology by which participant-related costs are allocated is called the substation fraction, which involves pro-rating the connection project's costs according to the capacity of each of the participants' contracted service (i.e., Rate DTS and Rate STS). However, the AESO also uses the substation fraction methodology, in part, to adjust participants' construction contributions as circumstances change, such as a change in the participants' contract capacities at a shared facility.

20. The DFO holds the contract for SAS for those participants downstream of it, for both supply and demand. Construction contributions for both Rate DTS (i.e., demand-related) and Rate STS (i.e., supply-related) are allocated to the DFO.[17]

3.2 Sections 28 and 47 of the Transmission Regulation

21. In the Decision, the hearing panel dismissed Fortis's argument that the AESO's substation fraction methodology is inconsistent with Section 28 of the *Transmission Regulation* and held that costs that have been deemed to be supply-related costs in relation to SAS provided to a DFO must be wholly charged to the DFO in accordance with Section 47(a) of the *Transmission Regulation*.[18] The Stage 1 panel determined that this issue was in scope of this variance proceeding.[19] For the reasons that follow, the Stage 2 panel is not persuaded to vary or rescind the hearing panel's determinations.

[16] In the context of the current decision, the term "shared facility" is used to describe situations where two or more market participants for SAS receive it (through, e.g., Rate DTS or Rate STS or both) using the same transmission facilities.
[17] Decision 22942-D02-2019, paragraph 816.
[18] Decision 22942-D02-2019, paragraphs 743-744.
[19] Exhibit 25848-X0004, Appendix A – Scope of Proceeding 25848, pages 5-6.

22. The Stage 2 panel finds that costs that have been deemed to be supply-related costs in relation to SAS provided to a DFO are costs that must be wholly charged to the DFO in accordance with Section 47(a) of the *Transmission Regulation*. This is because, as found by the hearing panel:

- Under Section 28(1)(a) of the regulation, local interconnection costs are payable by an owner of a generating unit "for connecting to the transmission system";[20] and
- "Where a SASR [SAS request] is received from a DFO, the market participant is not the owner of a generating unit, and the request does not involve the connection of a generating unit directly to the transmission system."[21]

23. For greater clarity, the Stage 2 panel confirms that the costs of the transmission system charged to owners of electric distribution systems are recoverable by the owner of the electric distribution system through its tariff,[22] and that the costs of the transmission system through the tariff of an owner of an electric distribution system may be recovered from DCGs.[23] The Stage 2 panel also acknowledges the Stage 1 panel's finding that the manner and quantum of the costs that the DFO flows through to the DCGs connected to specific DFO substations is a matter best addressed in the DFO's tariff and is not to be re-argued in this proceeding.[24]

3.3 Application of the substation fraction methodology to new projects

24. The Alberta Energy and Utilities Board, predecessor to the AUC, approved the substation fraction methodology in Decision 2005-096,[25] in part, to attribute initial connection costs, i.e., "customer contributions," to each of supply and demand in circumstances where there are costs to build or upgrade a transmission facility to connect both supply and load to the transmission system.[26]

25. In this proceeding, parties filed evidence that the substation fraction methodology is currently being used to reallocate costs as circumstances change, such as when Rate DTS and Rate STS contract capacities are adjusted and that, as a result, an existing market participant may be allocated costs that it did not cause, and which were not known at the time of the participant's connection to the facilities. The potential for such additional connection project costs to be reallocated to participants using existing facilities was referred to by some parties in the proceeding as the "unlimited liability issue," a term that is imprecise, but which was adopted by the Stage 2 panel in this decision for ease of reference. The DFO, in attempting to recover the

20 Decision 22942-D02-2019, paragraph 743.

21 Decision 22942-D02-2019, paragraph 744.

22 *Transmission Regulation*, Section 47(a)(ii).

23 Under Section 102 of the *Electric Utilities Act*, each owner of an electric distribution system must prepare a distribution tariff for the purpose of recovering the prudent costs of providing electric distribution service by means of the owner's electric distribution system. In the *Electric Utilities Act*, "electric distribution service" is defined as providing service to both "customers" and "distributed generation."

24 Exhibit 25848-X0004, Appendix A – Scope of Proceeding 25848, page 6.

25 Decision 2005-096: Alberta Electric System Operator (AESO), 2005/2006 General Tariff Application, Proceeding 14250, Application 1363012-1, August 28, 2005. In Section 6.1.6.1, "The AESO noted that the dual-use ratio [substation fraction] was intended to provide a reasonable sharing of customer-related costs between load and supply in consideration of the fact that a significant portion of the load customer's interconnection costs may be rolled into rates through the operation of the roll-in ceiling while the generator costs are paid fully by the generator as a customer contribution."

26 Decision 2005-096, Section 6.1.6.1 Application of Contribution Policy to Dual-Use Sites, PDF page 64.

costs allocated to it by the AESO, may in turn attribute a portion of these costs (and in particular the costs associated with a Rate STS construction contribution) to DCGs. The ability, discretion and timing of the DFO flowing these altered cost allocations through to DCGs also contributes to the unlimited liability issue.

26. The AESO proposed an immediate solution on an interim basis to resolve the unlimited liability issue. This solution, applicable to all new connection projects, is to set the substation fraction to one (SSF=1) at all DFO-contracted substations on a prospective basis. Setting SSF=1 has the effect of attributing all connection costs to Rate DTS contracts and none to Rate STS contracts. The AESO clarified that this proposal would entail:[27]

> (a) removing provisions in the ISO tariff that require the AESO to deem supply-related and demand-related amounts at DFO contracted substations;
>
> (b) revising the SSF definition in the Consolidated Authoritative Document Glossary; and
>
> (c) on a go forward basis, changing the Rate DTS bills at affected substations (i.e., DFO contracted substations where the substation fraction was not already set to one) to ensure alignment with the proposal. [footnote removed]

27. This proposal, which was advanced to provide investment certainty, was generally agreed to by the parties to this proceeding. While the AESO acknowledges that there are shortcomings with the proposal,[28] such as an increase in billing determinants under Rate DTS, the Stage 2 panel approves this proposal because it will address some of the ongoing risk to the market participants for SAS in the near term, and the AESO has committed to providing a long-term, comprehensive solution as part of the upcoming Phase 2[29] of its general tariff application (GTA). The proposal will be effective following Commission approval of specific tariff language to this effect, to be applied for in a compliance filing following the release of this decision.

28. The Stage 2 panel directs the AESO to file its compliance filing to this decision by January 11, 2021, with the necessary tariff amendments to implement the SSF=1 proposal. The Stage 2 panel expects that the compliance proceeding will be largely administrative in nature, and that no further participation by parties or substantial process will be required.

29. The Stage 2 panel's approval of the substation fraction methodology is final but will be of limited duration. It will be in effect until a new solution is approved by the Commission as a result of the AESO's forthcoming contribution policy module, Phase 2 of its GTA. The solution emerging from that module will replace this approval; the Commission will not revisit this approval.

30. In its submission, the AESO also proposed that for new DCG connection projects, DFOs would only be required to allocate to DCG incremental transmission connection costs that are caused directly by the DCG and are incurred for new or modified transmission connection

[27] Exhibit 25848-X0079, AESO reply submission, paragraph 9.

[28] The AESO identified the list of shortcomings in Exhibit 25848-X0059, AESO submission, paragraphs 17-18.

[29] In its submission in this proceeding, the AESO referred to this as "Phase II", e.g., Exhibit 25848-X0059. In its submissions related to the substation fraction and adjusted metering practice on the compliance filing to the Decision, Proceeding 25175, the AESO referred to this as "Phase 2," e.g., Proceeding 25175, Exhibit 25175-X0095, paragraph 49. The terminology in the current decision reflects the terminology used in Decision 25175-D02-2020, e.g., at paragraph 55.

facilities. The Stage 2 panel considers that the AESO's SSF=1 proposal partially resolves the unlimited liability issue and agrees that a complete resolution of this issue must ultimately be grounded in DFO tariffs. While the Stage 2 panel acknowledges that DFO flow-through matters are not within the scope of this proceeding,[30] [31] it nevertheless supports the principle of only flowing through to DCGs those incremental costs which result from the connection of the DCG to the distribution or transmission system or an alteration of connection facilities, as it considers that doing so would further market efficiency. This is described in more detail in Section 3.5 below.

31. The AESO also stated that DFOs are better positioned to accurately assess how transmission connection costs should be allocated among their end-use customers,[32] stating that DFOs have better access to the DCG cost and usage information needed to properly determine this question. Fortis objected to the AESO's assertion that the DFO is better positioned to assess allocation of transmission costs and requested that (i) the Commission confirm that the AESO's customer contribution proposals in its GTA should not depend on DFOs determining how transmission costs are allocated between load and DCG; and (ii) the ISO tariff address the allocation of these transmission costs.[33]

32. The Stage 2 panel finds that in order to facilitate DFOs accurately allocating incremental connection costs of the transmission system to the DCGs that caused those costs, the AESO must identify the costs of specific facilities required for the connection of DCG customers and communicate this information to the DFO. The Stage 2 panel therefore directs the AESO to clearly identify, to the extent practical, the DCG incremental transmission connection costs in all future customer contribution decisions (CCDs). The Stage 2 panel further directs the AESO to work with all DFOs to identify costs of specific facilities required for the connection of DCG customers on an ongoing basis. With respect to existing connection projects, the AESO is directed to inform DFOs of the relevant calculations as set out in paragraph 36 of this decision.

3.4 Application of the substation fraction methodology to existing projects

33. The Stage 2 panel acknowledges that, for some existing DCG projects connected to DFO-contracted substations, CCD recalculations may have allocated costs in excess of the incremental costs to the STS contract associated with their connection. These reallocations may not have reflected incremental costs caused by the DCG project and may not have occurred had the SSF=1 methodology been in place at the time of the recalculation.

34. The evidence shows that December 1, 2015, is the earliest date upon which a contract was affected accordingly.[34] All parties to Proceeding 22942 were aware of this issue by

[30] Exhibit 25848-X0004, Appendix A – Scope of Proceeding 25848, "The manner and quantum of the costs that the DFO flows through to the DCGs connected to specific DFO substations is a matter best addressed in the DFOs' tariff," page 6.

[31] In Exhibit 25848-X0054, Fortis maintained that the hearing panel erred when it found that DFOs have discretion to limit the amount of AESO contributions flowed through to DCGs and reserved the right to challenge this determination at another time. The Stage 2 panel understands that the Fortis Phase II distribution proceeding (Proceeding 25916) currently before the Commission includes a request to clarify Article 12 of its Customer terms and conditions of its tariff to address this issue, and no determinations of this Stage 2 is required to permit consideration in Proceeding 25916.

[32] Exhibit 25848-X0079, AESO reply submission, paragraph 20.

[33] Exhibit 25848-X0077, Fortis reply submission, paragraph 14.

[34] Exhibit 25848-X0047, Power Advisory submission for the CGWG, paragraph 66.

October 2, 2018, when the hearing panel directed the AESO to suspend the application of information document 2018-019T and gave all parties an opportunity to present their positions in that proceeding.[35] Although it recognizes that there is a general presumption against retroactivity, the Stage 2 panel finds that applying this presumption would not result in sound utility regulation in these circumstances and as further described below.[36]

35. The Stage 2 panel considers that the unlimited liability issue resulted from a combination of a new application of the substation fraction methodology to DFO-contracted substations, regulatory lag, and a lack of communication. In the Stage 2 panel's view, investors in affected DCG projects could not have reasonably anticipated the risk that these circumstances would have resulted in their connection costs being increased after their final investment decisions were made. The CGWG filed evidence showing affected DCG projects totalling approximately 57 megawatts of DCG experienced approximately $18 million of such connection cost increases.[37] The Stage 2 panel considers that such unanticipated cost increases represent material changes to affected projects which, left unaddressed, would increase investor risk and impair future investment in the Alberta electricity market. Accordingly, the Stage 2 panel finds that addressing those historical costs back to December 1, 2015, when the first contract was affected, would accord with principles of sound utility regulation and would be in the public interest. For any instance that has arisen since December 1, 2015, for which reallocations did not reflect incremental costs caused, the AESO is directed to reallocate those additional charges from the Rate STS contract to the Rate DTS contract at that DFO substation.

36. To facilitate a resolution of those projects that are affected, the AESO is directed to recalculate CCDs using SSF=1 and the principles articulated in Section 3.5 of this decision, and to inform affected DFOs of those recalculations. The DFOs can then work with DCGs to resolve any outstanding contribution concerns. If resolution among the DFOs, the AESO and other affected parties is unsuccessful, the Commission will resolve any disagreements.

37. The Stage 2 panel directs each DFO to file a report, as a post-disposition document to this proceeding, on or before March 31, 2021, setting out the details of all resolutions and outstanding disputes related to existing DCG projects connected to DFO-contracted substations, that received recalculated CCDs. The Commission will endeavour to consider these subsequent matters as expeditiously as possible.

3.5 Principles for future ISO tariffs

38. In Section 3.3 of this decision, the Stage 2 panel acknowledged that there are shortcomings with the SSF=1 proposal, but approved it on the basis that it would address some of the ongoing risk to the market participants for SAS in the near term. The AESO also

35 Proceeding 22942, Exhibit 22942-X0207, AUC letter - Ruling on ENMAX, CanSIA and Fortis motions, October 2, 2018.

36 See Decision 790-D02-2015, where the Commission determined that it can have recourse to any information it deems necessary or relevant from the tariff applicant or interveners in setting final tariff rates that meet the test of justness and reasonableness, in the context of a negative disallowance scheme, at paragraph 253. See also Decision 22942-D02-2019, paragraph 803, which cites the Court of Appeal in Alberta in *Capital Power Corporation v Alberta Utilities Commission*, 2018 ABCA 437, where the court stated that the rule of retroactive ratemaking is "is not so much a question of law but a question of whether or not a strict application of the rule in the circumstances of the case achieves sound utility regulation."

37 Exhibit 25848-X0047, Power Advisory submission for the CGWG, Table 1, PDF page 6.

committed to provide a long-term, comprehensive solution as part of its upcoming Phase 2 of its GTA.

39. The Stage 2 panel directs the AESO to consider the following principles on cost causation and cost allocation in the context of shared facilities, as they may be relevant to the development of its future Phase 2 tariff application:

- Supporting a fair, efficient and openly competitive market, with cost causation and cost allocation furthering economically efficient outcomes.

- Providing a level playing field in support of fair competition between TCG and DCG, when evaluating the allocation of transmission system costs to DCG.

- Costs should not be allocated to a DCG after the DCG has energized if the DCG does not directly cause those costs.[38]

3.6 Clarification of outstanding obligations from Proceeding 25058

40. The Stage 2 panel considers that Fortis's outstanding obligations from Proceeding 25058, the BluEarth complaint,[39] including the disposition of deferral accounts for DFOs,[40] may be resolved as a result of the findings and directions made in sections 3.3 and 3.4 of this decision. If they are not, any remaining matters related to the flow-through of CCD-related invoices for STS allocations associated with DCGs requiring Commission adjudication will be analyzed on a case-by-case basis in related distribution utility proceedings. The Commission will therefore close the BluEarth complaint. Fortis is directed to provide details of a proposal for the disposition of its deferral account established to deal with this complaint in the report requested by March 31, 2021, as indicated in paragraph 37 above.

4 Adjusted metering practice

41. In the original proceeding, the AESO proposed a new adjusted metering practice that changed the point of totalization from the high side of the substation (net) to the feeder level (gross). This has an impact on DCG credits and Rate STS contract capacities.

42. In sections 7.3.1 through 7.3.4 of the Decision, the hearing panel approved the AESO's proposed adjusted metering practice and found that the continuation of the current metering practices could cause a significant erosion of billing determinants. In Section 7.3.8, the hearing panel also found that a transition period was necessary, and that the change to the adjusted metering practice (from net to gross) will result in different treatment for parties who are grandfathered and those who are subject to the changed practice. The Stage 1 panel determined that these findings were not in the scope of this variance proceeding.

[38] Proceeding 25101, Exhibit 25101-X0044, Appendix A - Technical Session Objectives, Outcomes and Materials, PDF page 3.
[39] Proceeding 25058, BluEarth Renewables Inc., Application to Consider Complaint by BluEarth Renewables Inc. Against FortisAlberta Inc.
[40] Proceeding 25058, Exhibit 25058-X0030, AUC letter - Suspension of proceeding, December 10, 2019, paragraphs 7-9; Exhibit 25058-X0034, AUC letter – Direction to FortisAlberta Inc., December 19, 2019, paragraph 12; Exhibit 25058-X0048, BluEarth response to process proposal, August 4, 2020, PDF page 4.

43. However, the Stage 1 panel found, in reference to Section 7.3.8 of the Decision, that "the timing and the application of grandfathering, including the 'hybrid' grandfathering option proposed by the AESO in Proceeding 25175,"[41] as well as the issue of additional metering costs,[42] were within the scope of this variance proceeding.

44. For the reasons that follow, the Stage 2 panel (i) finds that the adjusted metering practice should be implemented without grandfathering; and (ii) directs the AESO to submit revised tariff language as part of its compliance filing and implementation details in its next Phase 2 tariff application, to operationalize the adjusted metering practice.

Grandfathering of the adjusted metering practice

45. Despite the Stage 2 panel's approval of SSF=1 in sections 3.3 and 3.4 of this decision, it was a proposal that was not before the hearing panel; consequently, the relationship between SSF=1 and the adjusted metering practice has not yet been examined.

46. Power Advisory, in its submission on behalf of the CGWG, summarized the interdependent relationship between the adjusted metering practice and substation fraction methodology, as follows:[43]

> The adjusted metering practice changes the point of totalization from the high side of the substation to the feeder. This has an impact on DCG Credits and Rate STS contract capacities. The Rate STS contract size in turn impacts the amounts allocated to STS under the substation fraction methodology. Accordingly, the adjusted metering practice and substation fraction approach are related only insofar as the adjusted metering practice may increase the size of Rate STS contracts for medium and large DCGs relative to the current POD [point of delivery] level totalization.
> …
>
> However, it is possible to implement the recommendation from the prior section (i.e., set the substation fraction equal to one at all DFO Substations) and simultaneously approve the adjusted metering practice. This would address the substation fraction issue and remove the interdependency between these two topics.

47. The Stage 2 panel agrees that implementing the recommendation to set the substation fraction equal to one removes the interdependency between the substation fraction issue and the adjusted metering practice. The Stage 2 panel finds, with respect to the calculation of the construction contribution, that because of its approval of SSF=1, those parties that would otherwise have been exposed to the potential for connection cost increases from new or increased STS contracts will no longer be exposed to that risk. Consequently, the Stage 2 panel finds that grandfathering is not necessary to address the unequal treatment in the calculation of contribution costs among DCGs.

---

41 Exhibit 25848-X0004, Appendix A – Scope of Proceeding 25848, PDF page 10. "The timing and the application of grandfathering, including the 'hybrid' grandfathering option proposed by the AESO in Proceeding 25175 is within the scope of the variance proceeding."

42 Exhibit 25848-X0004, Appendix A – Scope of Proceeding 25848, Section 7.3.5 Cost causation and cost allocation issues, pages 5-8; Section 7.3.11 Other Matters, DFO metering costs & complexity of implementation, page 13.

43 Exhibit 25848-X0047, Power Advisory submission for the CGWG, paragraph 77.

48. In their submissions on the adjusted metering practice, several parties supported the grandfathering of the adjusted metering practice in order to maintain DCG credits, which they argued were in the public interest. The Stage 2 panel recognizes that the implementation of the adjusted metering practice does affect the availability of metering information currently used for the calculation of DCG credits. However, the hearing panel determined that the continuation of DCG credits was a distribution tariff matter,[44] and the Stage 1 panel confirmed that finding. In addition, Proceeding 26090 was recently initiated to consider whether DCG credits should continue to be included in a distribution utility's tariff.[45] Should DCG credits be maintained as a result of the decision in Proceeding 26090, the Stage 2 panel considers that these credits could be supported by an alternate mechanism that, if necessary, will be addressed in that proceeding.[46]

49. The hearing panel was persuaded, in part, that there was a need to implement the AESO's adjusted metering practice to rectify billing determinant erosion. As found above, SSF=1 delinks the adjusted metering practice with connection costs. The Stage 2 panel therefore varies the hearing panel's findings at paragraph 796 of the Decision, and directs the AESO to implement the adjusted metering practice with no grandfathering provisions.

Compliance filing and Phase 2 tariff application

50. In order to bring into effect the direction in paragraph 44 of this decision, the AESO is directed to submit the proposed tariff language to implement the adjusted metering practice, as part of its compliance filing directed in Section 3.3 above.

51. The Stage 2 panel recognizes that in the proceeding leading to the Decision, the AESO did not provide details on the extent, timing or costs to install the new gross meters to fully operationalize the adjusted metering practice. No additional details were provided in this proceeding; the AESO simply requested approval of the proposed adjusted metering practice and none of the parties specifically commented on the extent, timing or costs to install the new gross meters to fully operationalize the adjusted metering practice.

52. The Stage 2 panel considers that there will be a natural transition period required to install the new gross meters, and that it will only be possible for the AESO to develop a plan to operationalize the adjusted metering practice following the approval of the compliance filing language. The Stage 2 panel therefore directs the AESO, in its Phase 2 tariff application,[47] to submit a plan setting out the details on how to operationalize the implementation, such as extent, timing, and costs of the adjusted metering practice.

---

44 Decision 22942-D02-2019, paragraph 787.

45 Proceeding 26090, Exhibit 26090-X0005, paragraph 9.

46 The scope of Proceeding 26090 included the following (Exhibit 26090-X0005, AUC letter - DCG credits and initial process schedule, November 17, 2020, paragraph 12): "… (iii) If in your response to (i) or (ii) you argue DCG credits should be retained as presently constituted or in some alternate form, please address potential level playing field considerations. For example, for DCG that would no longer receive DCG credits due to the AESO's adjusted metering practice, or were previously ineligible for DCG credits, and transmission-connected generation (which appears to have no access to a similar credit mechanism). (iv) If DCG credits were to be adjusted (either in ways contemplated in (ii) or entirely discontinued), what issues should be examined? For example, with what scope and timing should the adjustment be made?"

47 Decision 25175-D02-2020, paragraph 55: "The AESO anticipated filing Phase 1 on or before June 30, 2021, and stated it would advise the Commission of the new anticipated filing date for Phase 2 (after June 30, 2021) once determined."

5 Order

53. It is hereby ordered that:

    (1) The finding in paragraph 796 of Decision 22942-D02-2019 is rescinded, and the findings set out in paragraph 49 of this decision are substituted.

Dated on December 23, 2020.

Alberta Utilities Commission

(original signed by)

Anne Michaud
Vice-Chair

(original signed by)

Carolyn Dahl Rees
Chair

(original signed by)

Douglas A. Larder, QC
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Acestes Power ULC (Acestes) SABR Energy Consulting Inc.
Alberta Direct Connect Consumers Association (ADC)
Alberta Electric System Operator (AESO)
AltaLink Management Ltd. (AltaLink)
ATCO Electric Ltd. (ATCO)
Aura Power Renewables Ltd. (Aura)
BluEarth Renewables Inc. (BluEarth) Blake, Cassels & Graydon LLP
Canadian Renewable Energy Association (CanREA)
Canadian Solar Solutions Inc. (Canadian Solar)
Capital Power Corporation (Capital Power)
Capstone Infrastructure Corporation (Capstone)
Cascade Power Project Limited (Cascade) Osler, Hoskin & Harcourt LLP
Consumers' Coalition of Alberta (CCA)
Denis Forest
Distributed Generation Working Group (DGWG) TRW Consulting
Dual Use Customers (DUC) Desiderata Energy Consulting Inc.
Elemental Energy Renewables Inc.
ENMAX Corporation (ENMAX)
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) Borden, Ladner Gervais LLP
FortisAlberta Inc. (Fortis or FAI) Osler, Hoskin & Harcourt LLP
Greengate Power Corporation (Greengate) Edmond de Palezieux
Heartland Generation Ltd. (Heartland)

Name of organization (abbreviation) Company name of counsel or representative
Industrial Power Consumers Association of Alberta (IPCAA)
Irricana Power Generation (Irricana)
Kalina Distributed Power (Kalina) Regulatory Law Chambers
Lionstooth Energy (Lionstooth)
Longspur Developments (Longspur)
Métis Economic Trade and Industrial Services Corporation (MÉTIS Corp)
NAT-1 Limited Partnership (NAT1)
Neyaskweyahk Sundancer LP
Office of The Utilities Consumer Advocate (UCA) Brownlee LLP
Peters Energy Solutions Inc.
Siemens Energy Canada Ltd.
Taber Solar 2 Inc.
TransAlta Corporation (TransAlta)
University of Alberta Chymko Consulting Ltd.

Alberta Utilities Commission Commission panel A. Michaud, Vice-Chair C. Dahl Rees, Chair D.A. Larder, QC, Acting Commission Member Commission staff J. Graham (Commission counsel) A. Sabo (Commission counsel) G. Bourque E. Deryabina C. Fuchshuber

Appendix 2 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Stage 2 panel directs the AESO to file its compliance filing to this decision by January 11, 2021, with the necessary tariff amendments to implement the SSF=1 proposal. The Stage 2 panel expects that the compliance proceeding will be largely administrative in nature, and that no further participation by parties or substantial process will be required .... paragraph 28

2. The Stage 2 panel finds that in order to facilitate DFOs accurately allocating incremental connection costs of the transmission system to the DCGs that caused those costs, the AESO must identify the costs of specific facilities required for the connection of DCG customers and communicate this information to the DFO. The Stage 2 panel therefore directs the AESO to clearly identify, to the extent practical, the DCG incremental transmission connection costs in all future customer contribution decisions (CCDs). The Stage 2 panel further directs the AESO to work with all DFOs to identify costs of specific facilities required for the connection of DCG customers on an ongoing basis. With respect to existing connection projects, the AESO is directed to inform DFOs of the relevant calculations as set out in paragraph 36 of this decision. .... paragraph 32

3. The Stage 2 panel considers that the unlimited liability issue resulted from a combination of a new application of the substation fraction methodology to DFO-contracted substations, regulatory lag, and a lack of communication. In the Stage 2 panel's view, investors in affected DCG projects could not have reasonably anticipated the risk that these circumstances would have resulted in their connection costs being increased after their final investment decisions were made. The CGWG filed evidence showing affected DCG projects totalling approximately 57 megawatts of DCG experienced approximately $18 million of such connection cost increases. The Stage 2 panel considers that such unanticipated cost increases represent material changes to affected projects which, left unaddressed, would increase investor risk and impair future investment in the Alberta electricity market. Accordingly, the Stage 2 panel finds that addressing those historical costs back to December 1, 2015, when the first contract was affected, would accord with principles of sound utility regulation and would be in the public interest. For any instance that has arisen since December 1, 2015, for which reallocations did not reflect incremental costs caused, the AESO is directed to reallocate those additional charges from the Rate STS contract to the Rate DTS contract at that DFO substation. .... paragraph 35

4. To facilitate a resolution of those projects that are affected, the AESO is directed to recalculate CCDs using SSF=1 and the principles articulated in Section 3.5 of this decision, and to inform affected DFOs of those recalculations. The DFOs can then work with DCGs to resolve any outstanding contribution concerns. If resolution among the DFOs, the AESO and other affected parties is unsuccessful, the Commission will resolve any disagreements. .... paragraph 36

5. The Stage 2 panel directs each DFO to file a report, as a post-disposition document to this proceeding, on or before March 31, 2021, setting out the details of all resolutions and outstanding disputes related to existing DCG projects connected to DFO-contracted substations, that received recalculated CCDs. The Commission will endeavour to consider these subsequent matters as expeditiously as possible. .... paragraph 37

6. The Stage 2 panel directs the AESO to consider the following principles on cost causation and cost allocation in the context of shared facilities, as they may be relevant to the development of its future Phase 2 tariff application:

- Supporting a fair, efficient and openly competitive market, with cost causation and cost allocation furthering economically efficient outcomes.

- Providing a level playing field in support of fair competition between TCG and DCG, when evaluating the allocation of transmission system costs to DCG.

- Costs should not be allocated to a DCG after the DCG has energized if the DCG does not directly cause those costs. .... paragraph 39

7. The Stage 2 panel considers that Fortis's outstanding obligations from Proceeding 25058, the BluEarth complaint, including the disposition of deferral accounts for DFOs, may be resolved as a result of the findings and directions made in sections 3.3 and 3.4 of this decision. If they are not, any remaining matters related to the flow-through of CCD-related invoices for STS allocations associated with DCGs requiring Commission adjudication will be analyzed on a case-by-case basis in related distribution utility proceedings. The Commission will therefore close the BluEarth complaint. Fortis is directed to provide details of a proposal for the disposition of its deferral account established to deal with this complaint in the report requested by March 31, 2021, as indicated in paragraph 37 above. .... paragraph 40

8. For the reasons that follow, the Stage 2 panel (i) finds that the adjusted metering practice should be implemented without grandfathering; and (ii) directs the AESO to submit revised tariff language as part of its compliance filing and implementation details in its next Phase 2 tariff application, to operationalize the adjusted metering practice.

.... paragraph 44

9. The hearing panel was persuaded, in part, that there was a need to implement the AESO's adjusted metering practice to rectify billing determinant erosion. As found above, SSF=1 delinks the adjusted metering practice with connection costs. The Stage 2 panel therefore varies the hearing panel's findings at paragraph 796 of the Decision, and directs the AESO to implement the adjusted metering practice with no grandfathering provisions. .... paragraph 49

10. In order to bring into effect the direction in paragraph 44 of this decision, the AESO is directed to submit the proposed tariff language to implement the adjusted metering practice, as part of its compliance filing directed in Section 3.3 above........... paragraph 50

11. The Stage 2 panel considers that there will be a natural transition period required to install the new gross meters, and that it will only be possible for the AESO to develop a plan to operationalize the adjusted metering practice following the approval of the compliance filing language. The Stage 2 panel therefore directs the AESO, in its Phase 2 tariff application, to submit a plan setting out the details on how to operationalize the