Decision **23393-D01-2019**

Alberta Utilities Commission

Alberta Electric System Operator
Needs Identification Document Application

AltaLink Management Ltd.
Facility Application

Fincastle 336S Substation Upgrade

February 14, 2019

Alberta Utilities Commission
Decision 23393-D01-2019: Fincastle 336S Substation Upgrade

Alberta Electric System Operator
Needs Identification Document Application
Application 23393-A001

AltaLink Management Ltd.
Facility Application
Application 23393-A002

Proceeding 23393

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1 Decision summary

1. In this decision, the Alberta Utilities Commission must decide whether to approve a needs identification document (NID) application from the Alberta Electric System Operator and a facility application from AltaLink Management Ltd. for transmission development in the Taber area.

2. Aura Power Renewables Ltd. intervened, raising concerns with FortisAlberta Inc.'s load forecasting and use of deterministic planning and argued that the Alberta Electric System Operator (AESO) did not engage in a cost-benefit analysis, which if undertaken, would show that the project is not in the public interest. Aura also proposed a load-shedding alternative to the project. Aura submitted that the NID application was technically deficient and not in the public interest, and that the Commission should therefore reject the AESO's application.

3. For the reasons that follow, Commission members Jamieson and Phillips (referred to in this decision as the majority) found the AESO's assessment of the need to be correct. The majority was satisfied that FortisAlberta's load forecasting provided adequate justification for the need identified in its system access service request. The majority concluded that the AESO acted reasonably and consistently in reviewing the need and that its selection of the preferred transmission development is reasonable and in keeping with its statutory mandate. The majority also concluded that Aura's proposed non-wires alternative was not feasible, nor that it was sufficient to demonstrate that the AESO's preferred alternative is technically deficient or approval of the NID is not in the public interest. The majority also found that approval of the facility application is in the public interest having regard to the social, economic, and other effects of the project, including its effect on the environment.

4. In a dissenting opinion, Vice-Chair Michaud found that Aura had satisfied her that approval of the NID is not in the public interest. She found that the AESO's interpretation of its obligations under the *Electric Utilities Act* constrained its assessment of the underlying need for the project. As a result, the AESO did not properly assess whether the project was needed and in the public interest pursuant to Section 34(1) of the *Electric Utilities Act*. Vice-Chair Michaud concluded that Aura had overturned the presumption of correctness in Section 38(e) of the *Transmission Regulation*, and that the application should be referred back to the AESO for it to weigh the potential costs and benefits of the project to determine whether the proposed development is needed and in the public interest. Vice-Chair Michaud found that given her findings on the NID, it was unnecessary to make a determination on the facility application.

5. In reaching the determinations set out in this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence, argument, and reply argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

2 Introduction and background

6. Except in the case of critical transmission infrastructure, two approvals from the Commission are required to build and operate new transmission capacity in Alberta. First, an approval of the need for expansion or enhancement to the Alberta Interconnected Electric System, pursuant to Section 34 of the *Electric Utilities Act*,[1] is required. Second, a permit to construct and a licence to operate a transmission facility, pursuant to sections 14 and 15 of the *Hydro and Electric Energy Act*,[2] must be obtained.

7. The AESO filed a NID application with the Commission seeking approval to upgrade the Fincastle 336S Substation, including the addition of one 138/25-kilovolt (kV) transformer with a transformation capability of 25 megavolt ampere (MVA), two 138-kV circuit breakers and four 25-kV circuit breakers. The NID was prepared in response to a system access service request filed by FortisAlberta, the owner of electric distribution facilities in the Taber area, to reliably serve load growth in the area.

8. The AESO directed AltaLink to file a facility application with the AUC to meet the need identified and to assist the AESO in conducting a participant involvement program for its NID. AltaLink filed a facility application with the Commission for approval to build the facilities identified in the AESO's NID application. AltaLink's application is for approval to alter and operate the Fincastle 336S Substation (the project). The scheduled in-service date for the project is June 1, 2019.

9. In this proceeding, the Commission is considering two aspects of the project: (i) the AESO's assessment of the need for the project, and (ii) AltaLink's application to alter the Fincastle 336S Substation.

2.1 Legislative scheme

10. The AESO, in its capacity as the independent system operator established under the *Electric Utilities Act*, is responsible for preparing a NID and filing it with the Commission for approval pursuant to Section 34 of the *Electric Utilities Act*.

11. Section 34(1) of the *Electric Utilities Act* requires the AESO to file a NID if it determines that an expansion or enhancement of the Alberta Interconnected Electric System "is or may be required to meet the needs of Alberta and is in the public interest" in three circumstances: (a) there is a system constraint or condition affecting performance; (b) there is a need to improve efficiency; or (c) the AESO receives a request for system access service from a market participant. Section 29 of the *Electric Utilities Act* provides that the AESO "must provide system

[1] *Electric Utilities Act*, RSA 2000, c E-5.1.
[2] *Hydro and Electric Energy Act*, RSA 2000, c H-16.

access service on the transmission system in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so."

12. Subsection 38(e) of the *Transmission Regulation* requires the Commission to consider the AESO's assessment of need to be correct unless an interested person satisfies the Commission that the assessment is technically deficient, or that approval of the NID would not be in the public interest.

13. When making a decision on a contested NID, the Commission has three options; it may approve the application, deny it, or refer it back to the AESO with suggestions or directions for changes or additions.[3]

14. Facility applications are prepared by a transmission facility owner assigned by the AESO. When considering an application for a transmission facility, the Commission must consider whether the proposed transmission facilities are in the public interest having regard for the social and economic effects of the transmission facilities and their effect on the environment. AltaLink was assigned as the transmission facility owner by the AESO for this application.

2.2 Process

15. On March 28, 2018, the Commission issued a notice of applications for Proceeding 23393 with a deadline for submissions of April 18, 2018. The notice was sent directly to all stakeholders within 800 metres of the project. The notice was also published on the AUC website and notification was automatically emailed to eFiling System users who had chosen to be notified of notices of application issued by the Commission.

16. In response to the notice, the Commission received a statement of intent to participate from Aura.[4] In its submission, Aura requested that the Commission either: (i) suspend Proceeding 23393 until a decision is made in Proceeding 22942, the 2018 Independent System Operator (ISO) Tariff Application; or (ii) provide assurance that Aura would not be required to pay for any portion of the applied-for facilities, directly or indirectly, through FortisAlberta. In its standing ruling the Commission indicated that Aura's concerns with the application of the ISO Tariff and its proposed changes to the tariff were out of scope for this proceeding, but that Aura had standing in a limited manner, in relation to its stated concerns respecting the need for the project.[5]

17. The Commission's process schedule included two rounds of information requests and a written hearing.[6] On August 20, 2018, the Commission issued a notice of written hearing for Proceeding 23393, setting a deadline for written intervener evidence of October 1, 2018.

[3] *Electric Utilities Act*, Section 34(3).
[4] Exhibit 23393-X0029, Statement of intent to participate.
[5] Exhibit 23393-X0044, AUC Ruling on Aura Power Renewables Ltd. standing and motion.
[6] Exhibit 23393-X0053, AUC letter to parties Re: Information response submissions by the AESO; Exhibit 23393-X0054, Aura Letter to AUC - Request for Further Process; Exhibit 23393-X0055, LT AUC Comments re further process 2018-08-09; Exhibit 23393-X0056, AUC ruling on further process requested by Aura Power Renewables Ltd.

2.3 Aura Power Renewables Ltd.'s intervention

18. Aura is the developer of a proposed generation project to be connected to a FortisAlberta distribution feeder that connects to the Fincastle 336S Substation. Aura's project is listed as a behind-the-fence project on the AESO's project list and identified as 1949, FortisAlberta Fincastle DER Solar.[7]

19. Aura expressed concerns that changes to the ISO tariff proposed in Proceeding 22942 (2018 ISO Tariff Application) would increase the cost of the proposed facilities that would be allocated to Aura. Aura would potentially be allocated a significant portion of the cost of this project, an estimated $3 million,[8] which is neither desired nor expected to significantly benefit it. Further, Aura claimed that the existing substation provides for the capacity needs of FortisAlberta's customers and Aura's project.[9]

20. As part of its written evidence, Aura stated that the purpose of its evidence is to satisfy the Commission that the AESO's assessment of the need is technically deficient and not in the public interest. Aura argued:

- FortisAlberta's method of forecasting load growth leads to over-estimation of the risk of unsupplied load resulting from potential equipment failures. This results in the potential for overbuilding the transmission and distribution systems, which is not in the public interest.

- The minimal system reliability benefit which the proposed facilities could generate does not justify the construction costs of FortisAlberta's proposed expenditures in the Taber area of up to $28.5 million, which includes a $6 million expenditure at Fincastle. This cost and benefit imbalance is not in the public interest.

- FortisAlberta did not consider non-wires solutions to address the potential risk of unsupplied load. As an example, a load-shedding program would be considerably less costly than the proposed facilities.[10]

21. Aura requested that the Commission reject the proposed NID application for the Fincastle 336S Substation upgrade. Aura further requested that the Commission direct FortisAlberta, in all future applications for facilities serving a reliability purpose in the area: (i) to conduct a cost-benefit analysis to determine whether the proposed upgrades are appropriate; and (ii) to consider less expensive alternatives to address the perceived N-1 unsupplied load, such as through a voluntary load-shedding program. Aura stated that such programs already exist.

3 Needs identification document

22. The NID in this proceeding arises from a request by FortisAlberta, the owner of electric distribution facilities in the Taber area, for system access service from the AESO to reliably

7 Exhibit 23393-X0029, Aura Statement of intent to participate.
8 Exhibit 23393-X0099, Aura Written Evidence, paragraph 2.
9 Exhibit 23393-X0029, Statement of intent to participate.
10 Exhibit 23393-X0099, Aura Written Evidence, PDF pages 5 and 6.

serve load growth in the area. FortisAlberta's request included a rate demand transmission service (DTS) contract increase of 6.8 megawatts (MW), from 12.2 MW to 19 MW, for the system access service provided at the existing Fincastle 336S Substation. The AESO prepared its NID application in response to FortisAlberta's system access service request (SASR).

23. The AESO filed FortisAlberta's need for development report for the Taber area as part of its NID application. The report provided historical and forecast peak load levels for substations and feeders in the study area. The report also presented three alternatives, described as having "either the least distribution system development or the lowest estimated distribution capital cost,"[11] to reliably serve load growth in the area. A summary of these alternatives is found in Table 1 below.

Table 1. Alternatives assessed in FortisAlberta's need for development report

Alternative	Description	Distribution Cost (million (2018$, ±30%))
1	distribution system upgrades and load shifting at Taber 83S, Westfield 107S, Hull 257S, Fincastle 336S and Burdett 368S	$27.6
2	addition of a transformer and two circuit breakers at Fincastle 336S followed by associated distribution upgrades	$16.4
3	addition of a transformer at Fincastle 336S and a transformer at Hull 257S	$15.4

24. FortisAlberta determined that although Alternative 1 could be accomplished without affecting the transmission system, the distribution cost of this alternative would be significantly higher than the other alternatives. FortisAlberta indicated that Alternative 2 had the second lowest distribution capital cost, being $1.0 million more than that for Alternative 3. With respect to Alternative 3, FortisAlberta stated that while upgrading both the Fincastle 336S and Hull 257S substations had a lower distribution cost (i.e., $1.0 million) than Alternative 2, Alternative 3 had the addition of two source transformers instead of only one transformer for Alternative 2. The additional transformer would cause the transmission capital cost to be significantly higher than the $1.0 million difference in distribution capital cost. FortisAlberta's need for development report concluded that Alternative 2 was the lower cost option, and therefore its preferred alternative.

25. In its need for development report, FortisAlberta also attached a "Supplemental to Need for Development" document that included an updated Table 3-1 (i.e., FortisAlberta Historic and Forecast Load: Existing System).[12] In that document, FortisAlberta stated that the reliability concern at the Burdett 368S Substation in the year 2023 would no longer be predicted in the updated planning horizon, 2017 through to 2026. Further, FortisAlberta stated that the previously-requested rate DTS increase at the Fincastle 336S Substation required an adjustment of 6.8 MW resulting in a revised rate DTS of 19 MW. FortisAlberta indicated that the three previously-stated alternatives remained valid notwithstanding the updated need for development report information, and that it continued to favour Alternative 2, upgrades to the Fincastle 336S Substation, as its preferred alternative.

[11] Exhibit 23393-X0007, Section 4, page 4 of 19.
[12] Exhibit 23393-X0007, DFO Need for Development Report, PDF page 25.

26. In its NID, the AESO indicated that FortisAlberta's request could be met by the project, which involves upgrading the Fincastle 336S Substation through the addition of one 138/25-kV transformer, two 138-kV circuit breakers and four 25-kV circuit breakers (essentially, FortisAlberta's Alternative 2).[13] The AESO considered one transmission alternative to the project that was equivalent to FortisAlberta's Alternative 3: upgrades to the Fincastle 336S and Hull 257S substations. The AESO ruled out this alternative due to increased transmission development and overall increased cost compared to the preferred alternative. The AESO's connection assessment did not identify any expected system performance issues either before or after the implementation of the project.

27. The AESO's estimated in-service cost of the project was approximately $6 million. The AESO determined that the costs associated with the project would be classified as participant-related.

28. The AESO stated it had met its statutory obligations in the preparation and submission of the NID. It submitted that its need assessment is technically sufficient and its application is in the public interest. The AESO argued that Aura raised a number of issues outside of the current legislative framework due to its concerns about potential impacts to its business interests. The AESO noted that those issues are either beyond the scope of this proceeding or beyond the scope of the AESO's mandate.

29. FortisAlberta explained that it understood Aura's concern to be that its proposed generation project may not be economically viable if the project is approved, given the manner in which supply and demand related transmission costs are currently allocated at the point-of-delivery (POD) substations, such as the Fincastle 336S Substation. FortisAlberta argued that Aura has attempted to demonstrate that the project is not necessary, seemingly in an effort to preserve the economic viability of its proposed generation project. FortisAlberta submitted that the position of one commercially-motivated customer should not be permitted to vitiate the necessity of the proposed transmission development.

3.1 Load forecasts

3.1.1 Views of Aura

30. Aura's principal concern with the analysis the AESO relies upon to justify the need for the project is that FortisAlberta's method of forecasting load growth leads to overestimation of the risk and quantity of unsupplied load resulting from potential transformer failures. This could result in overbuilding the transmission and distribution systems, which is not in the public interest. Aura argued that FortisAlberta's forecasting methodology is flawed in two respects: "(i) its forecast of peak loads at substations is consistently higher than the actual peak loads; and (ii) its deterministic approach of comparing the worst case (highest) load to the N-1 substation capacity vastly overstates the potential unsupplied load."[14]

[13] Exhibit 23393-X0002, Fincastle 336S Substation Upgrade NID, PDF page 2.
[14] Exhibit 23393-X0111, Final Argument Aura Power, PDF page 7.

31. The result is that FortisAlberta's forecasts consistently over-estimate the risk of unsupplied load, which in turn cause FortisAlberta to overstate the need for system reliability improvements.

32. Aura provided an excerpt from the AESO's latest tariff application[15] that Aura claimed showed the AESO's doubt as to the accuracy of distribution facility owner (DFO) load forecasting methodologies and results. In describing load forecast process improvements and transmission over-build risk mitigation measures, the AESO stated:

> A further forecast process change is the consideration of DFO load forecasts in the AESO's load forecast process. The AESO routinely requests DFO load forecasts by substation because DFOs have information on projects and anticipated load growth beyond the transmission system, which the AESO does not have. In past AESO load forecasts, the DFO load forecasts were given significant weight. While DFO load forecasts continue to help provide the AESO with information regarding where DFOs forecast load-growth-related development, <u>the AESO is now placing less weight upon DFO load forecasts due to the AESO's review of historical DFO forecast accuracy and an enhanced understanding of DFO load forecast methodologies</u>.[16]

33. In its written evidence, Aura stated that the proposed facilities are not a requirement for basic service, but rather a reliability enhancement. Aura submitted that the likelihood of a transformer failure at Fincastle 336S Substation is extremely small. Further, Aura argued that the likelihood of a transformer failure occurring simultaneously with all electricity loads in the region consuming at their historical peaks is statistically minuscule and not adequate to justify the cost of the project.

34. Aura stated that the likelihood of a transformer failure (N-1 conditions) is rare, and that the following table provided by AltaLink illustrates the number of outages between 2012 and 2016:[17]

July 16, 2018

AESO-Aura-2018JULY04-002
Fincastle 336S Substation Upgrade
Application No. 23393-A001 and 23393-A002
Proceeding ID. 23393

ALTALINK
A BERKSHIRE HATHAWAY ENERGY COMPANY

Table 5 - Summary of Transformer Bank Statistics by Voltage Classification for Forced Outages Involving Integral Subcomponents

Voltage Classification	Component Years (a)	Sustained Outages: Number of Outages	Sustained Frequency (per a)	Total Time (h)	Mean Duration (h)	Median Duration (h)	Unavailability (%)
Up to 109 kV	221.6290	1	0.0045	73.15	73.15	73.15	0.0037
110 - 149 kV	1647.5816	17	0.0103	1,668.07	98.12	25.35	0.0115
200 - 299 kV	361.7498	7	0.0194	1,713.92	244.85	98.32	0.0540
500 - 599 kV	51.0659	1	0.0196	30.25	30.25	30.25	0.0067
All Voltage Classes	2282.0263	26	0.0114	3,485.38	134.05	30.67	0.0174

Source: CEA 2012-2016 Annual Report: AltaLink Forced Outage Performance of Transmission Equipment.

15 Exhibit 23393-X0111, Final Argument of Aura Power, PDF page 7.
16 Exhibit 23393-X0111, Final Argument of Aura Power, PDF page 7. [original emphasis]
17 Exhibit 23393-X0099, Aura Written Evidence, PDF page 8, citing Exhibit 23393-X0048, Attachment - AML AESO-Aura-2018JULY04-002, PDF page 2.

35. Aura stated that "[t]he table shows that the type of transformers used in the substations in the Taber area (110 – 149 kV) have an outage frequency of 1.03% per year (17 outages in 1647.6 component years) and an unavailability rate of 0.0115% (1668 outage hours in 1647.6 component years [14.4 million component hours])." Aura submitted that in other words, "these transformers can be statistically expected to be available 99.99% of the time."[18]

36. Aura's evidence was that in order to assess the potential for unsupplied load, FortisAlberta forecasts peak load by simply summing the historical peak load or contracted committed load, whichever is greater, for each individual user without consideration for their coincidence, and then compares this to the N-1 system capacity (capacity when one transformer has failed).[19] Aura stated that the likelihood of all electrical loads in the area supported by a specific transformer consuming at their historical peaks or forecasted peaks at the same time the transformer fails is extremely small. FortisAlberta's approach does not appropriately deal with the stochastic nature of events such as transformer failures and coincidental peak consumption. Aura stated that probabilistic modelling could be used to perform analysis that appropriately accounts for stochastic events and would provide reasonable expected values for unsupplied load, if any.

37. Aura argued that FortisAlberta's forecasting method is contributing to a pattern of over-prediction of future load. Aura provided an example where in 2015, FortisAlberta over-predicted the 2016 peak load for the substations in the Taber area by some 40 MVA compared to the actual peak load of about 125 MVA, a 30 per cent over-prediction.[20] Aura stated that the most significant driver of the proposed project's load increase is the expected growth in existing and new contracted loads. Aura highlighted an information request response from FortisAlberta in which it explained:

> Forecast peaks must include customer committed loads because of FortisAlberta's statutory obligation to ensure transmission and distribution capacity is available, which means that the contracted peak demands can be delivered when the customer requires.[21]

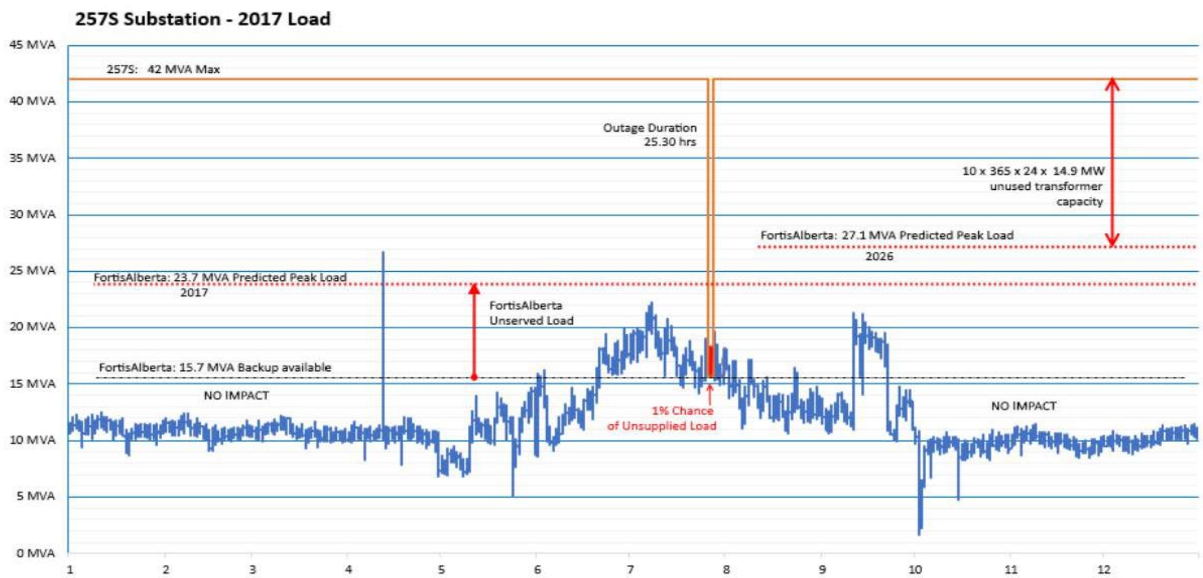
38. Aura stated that FortisAlberta's explanation above is reasonable for N-0 conditions, when there is no transformer failure. Aura argued, however, that for an N-1 analysis, which should aim to make the most realistic assessment of potential unsupplied load, this approach would inevitably contribute to over-prediction of peak load and consequently to over-prediction of unsupplied load in the event of a transformer failure.

39. Aura conducted its own probabilistic modelling to assess the level of unsupplied load, if any, that would result from a transformer failure at the Fincastle 336S Substation. Aura examined a hypothetical outage at the Hull 257S Substation during July 2017, as follows:

> The capacity at the Substation is 42 MVA and if a transformer were to fail, backup services from other proximate substations would provide 15.7 MVA of capacity. This is the N-1 capacity. The example shows that for most of this period of a few days in July, the load would be below the 15.7 MVA level and therefore, there would be no unsupplied load. In fact, given that load is typically lower outside of the summer months, the risk of

18 Exhibit 23393-X0099, Aura Written Evidence, PDF page 8.
19 Exhibit 23393-X0099, Aura Written Evidence, PDF page 8.
20 For visual representation, please see PDF page 10 of Exhibit 23393-X0099, Aura Written Evidence.
21 Exhibit 23393-X0099, Aura Written Evidence, PDF page 11.

unsupplied load is absent for most of the year (i.e., there is no impact even if a transformer fails). By comparison, FortisAlberta's analysis uses the predicted peak load of 23.7 MVA for 2017 and compares that to the N-1 capacity of 15.7 MVA and concludes that a reliability concern exists without taking into consideration the probability that this peak load level (or anything close to it) would actually occur at the same time as a transformer failure. The illustration below and the results of Aura's probabilistic modelling shows that this would be an extremely rare occurrence.[22]



40. In response to an information request from the Commission, Aura clarified that the numbers 1 to 12 on the horizontal axis of the above chart represent the months of the year 2017, from January to December.[23]

41. Aura argued that the risk presented by FortisAlberta is a worst-case scenario that fails to consider the probability of a transformer failure. Aura submitted that for the foreseeable future, 14.9 MW of substation capacity would remain unused, at the very least.

42. Aura's view is that FortisAlberta has a record of over-predicting loads. Using probabilistic modelling rather than FortisAlberta's simplistic approach, Aura determined that the unsupplied load would be at most 57 MWh over a 10-year period, which represents 0.0008 per cent of the more than 7,000,000 MWh that FortisAlberta is expected to deliver in this area over a 10-year period. As a result, Aura submitted that FortisAlberta would be able to meet its load requirements 99.99 per cent of the time without making any system modifications or spending up to $28.5 million, which Aura estimates as the cost of the proposed project plus other associated distribution expenditures in the Taber area.

43. Aura submitted that the value of probabilistic methods is that they can be used to quantitatively assess random events, a function unavailable through deterministic modelling which inevitably leads to over-prediction of unsupplied load and increases the potential for

22 Exhibit 23393-X0099, Aura Written Evidence, PDF pages 13 and 14.
23 Exhibit 23393-X0104, Aura Responses to AUC, PDF page 12.

overbuilding the transmission and distribution systems. Further, Aura stated that FortisAlberta acknowledged there is value in applying probabilistic methods for N-2 contingency planning, but provided no rationale as to why it could not also be used for N-1 contingencies.[24] In addition, Aura submitted that the AESO had adopted a probabilistic approach for load forecasting that was endorsed by the Alberta Energy and Utilities Board in Decision 2005-005 regarding the AESO's 2004 General Tariff Application.[25]

3.1.2 Views of the AESO and FortisAlberta

44. The AESO submitted that in reviewing distribution facility owner (DFO) requests for system access service, it assesses the information provided by the DFO which articulates the distribution deficiency, but that it would be overreaching for the AESO to second-guess the DFO's distribution planning decisions and forecasts in support thereof.[26] FortisAlberta provided evidence and submissions along with the AESO's argument with respect to its forecasting methodology.

45. The AESO indicated that Aura's reference to Decision 2005-005 was made in response to FortisAlberta's evidence that "the deterministic approach to electric power system planning is the acceptable method in Alberta" and that "[o]ther Alberta DFOs use this approach, as does the AESO."[27] The AESO asserted that there is an important distinction between probabilistic forecasting and probabilistic planning. The AESO explained that Decision 2005-005 referred to the AESO's use of probabilistic forecasting in a materially different context. The AESO uses a deterministic approach for the purpose of planning transmission developments to enable system access service, and its comments in Decision 2005-005 do not apply to the AESO's planning approach in this proceeding.[28]

46. FortisAlberta argued that Aura misunderstood the use of load forecasting and the distinction between capacity planning and reliability planning.[29] FortisAlberta explained that the premise for the excerpt from Decision 2005-005 is capacity planning, not reliability planning. It is the AESO's obligation to engage in system-wide transmission capacity planning and, in doing so, it uses a probabilistic approach to develop capacity planning for transmission losses, operating reserves, generator outputs and export and import volumes. The AESO does not state or imply that it uses a probabilistic approach in transmission reliability planning. FortisAlberta submitted that Decision 2005-005 dealt with completely different issues and is not relevant to this proceeding.

47. In response to Aura's argument that the likelihood of transformer failures is very small, FortisAlberta stated that Aura's table[30] and the outage frequency descriptive statistics therein are only based on transformer equipment subcomponents. FortisAlberta elaborated that the statistics do not account for failures in other equipment, such as terminal equipment, which could also result in a loss of supply from POD substations to the distribution system. FortisAlberta argued

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24 Exhibit 23393-X0111, Final Argument of Aura Power, PDF page 9.
25 Exhibit 23393-X0111, Final Argument of Aura Power, PDF page 9, citing Decision 2005-005, Alberta Electric System Operator 2004 General Tariff Application, Phase I, January 31, 2005, page 12.
26 Exhibit 23393-X0109, AESO Written Argument, paragraph 29.
27 Exhibit 23393-X0111, Final Argument Aura Power, PDF page 9, paragraph 23.
28 Exhibit 23393-X0113, AESO Reply Argument, PDF page 8.
29 Exhibit 23393-X0114, 2018-11-21 FortisAlberta Reply Submission, Paragraph 17, PDF page 9.
30 Exhibit 23393-X0099, Aura Written Evidence, PDF page 8.

that this omission is significant and materially skews the content in Aura's table. FortisAlberta stated that for 110 to 149-kV voltage class transformers, AltaLink statistics show that the inclusion of terminal equipment increases forced outage frequency by a factor of approximately 4.5.[31]

48. FortisAlberta argued that the project is not reliant on either deterministic or probabilistic load forecasting; rather, it is based on actual metered feeder peak load levels which indicate that unsupplied load would exist under N-1 contingencies. FortisAlberta submitted that this distinction is significant, as there is no uncertainty arising from forecasting and that *actual* unsupplied load would exist in the event of an N-1 contingency if the project is not implemented.

49. In response to Aura's written evidence that FortisAlberta determines peak load for each individual user without any consideration to coincidence, FortisAlberta rebutted that its load forecasting methodology does include the application of coincident factors because it is an effective tool to ensure that the capacity requirements are not overstated at POD substations.[32] FortisAlberta elaborated that it applies a coincidence factor to each of the committed loads prior to their inclusion in the load forecast and applies a coincidence factor to the individual distribution feeder peaks to determine the anticipated peak loads on the substation transformer. The resultant anticipated peak loads on the substation transformers are then totalled, with the application of a coincidence factor to the individual calculated substation transformer loads, to determine the total substation predicted peak loads. FortisAlberta submitted that coincidence factors for transformers at a common substation are usually between 90 per cent and 100 per cent.

50. Further, FortisAlberta stated that it understood the AESO's comments regarding reduced reliance on DFO load forecasts in the context of the 2018 ISO Tariff Application to be the result of the AESO's need to explain differences between its load forecasting methodology and that of DFOs like FortisAlberta, which stem from the differing needs of the AESO and DFOs. FortisAlberta explained:

> Each of the AESO and the DFOs use forecasting methods that address their respective system planning needs. Specifically, while FortisAlberta uses a "bottom-up" load forecast approach by taking localized loads down to the <u>individual customer level</u> and projecting this trend over time to meet customer needs and customer committed loads, the AESO's load forecast methodology is a blend of top-down, economics-based Alberta Internal Load (AIL) peak forecasts combined with bottom-up hourly <u>Point-of-Delivery (POD)-level</u> load shapes.[33]

51. It is the differing needs of the two entities and not inherent issues with the DFOs' load forecasting which drove the AESO's reduced reliance on DFO load forecasts. FortisAlberta argued that its load forecasting methodology is not flawed:

> While Aura asserts that the Company's methodology leads to over-estimation of risk because its forecast of peak loads at substations is consistently higher than the actual peak loads, this propensity is by design and does not represent deficient forecasting methods. Indeed, the Company's "Forecast" peaks identify the upper bounds of electric system

31 Exhibit 23393-X0107, 2018-11-06 FortisAlberta Information, PDF page 10.
32 Exhibit 23393-X0107, 2018-11-06 FortisAlberta Information, PDF page 6.
33 Exhibit 23393-X0114, FortisAlberta Reply Submission, PDF page 7. [original emphasis]

> peak capacity that would be required annually to address customer needs. These peaks are inclusive of generic small customer load growth and customer committed loads (new and existing) that may or may not materialize in any given year.
>
> Similarly, Aura attempts to characterize FortisAlberta's "deterministic approach" as "vastly overstat[ing] the potential unsupplied load". However, in doing so, Aura fails to appreciate that the essence of deterministic planning is to create a reliable system that can satisfy peak customer demands during an N-1 contingency event. In other words, the Company's approach does not "vastly overstate the potential unsupplied load" but rather ensures that the system can continue to meet unsupplied load during peak times in accordance with Good Utility Practice.[34]

52. In response to Aura's submission that FortisAlberta's predicted load forecast overstates load in the area, FortisAlberta explained that its "forecast" peaks must include individual customer contracted peak demands. Because FortisAlberta has a statutory obligation to ensure that transmission and distribution capacity is available, it must ensure that contracted peak demands can be delivered when required by the customer. Accordingly, FortisAlberta's "forecast" peaks will always be higher than "actual" peaks.[35]

53. FortisAlberta stated that Aura's assertions regarding N-0 conditions are also irrelevant and inapplicable to the Commission's evaluation of the project. FortisAlberta argued that to suggest that it is only required and permitted to plan and build to ensure the provision of safe and reliable service under N-0 contingency conditions suggests that the distribution system need only operate reliably under normal "non-contingency" conditions. Such an approach would effectively prevent backup planning and would be inconsistent with both Good Utility Practice and the public interest.

54. FortisAlberta stated that it uses a deterministic approach for N-1 contingencies in its distribution planning. It explained that this approach is based on the premise that an outcome could be accurately predicted to the extent that all necessary variables are known and quantified. FortisAlberta stated that in practice, this would mean that compliance with its planning criteria would, all else being equal, ensure an ability to restore power during an N-1 contingency. FortisAlberta argued that this is not equivalent to 100 per cent reliability, as Aura asserted in evidence. FortisAlberta added that its execution of distribution planning using a deterministic approach, as well as its consistent utilization of established distribution planning criteria and peak demand to identify violations to the distribution system planning criteria are all consistent with Good Utility Practice. FortisAlberta submitted that the deterministic approach to electric power system planning is the acceptable method in Alberta and that other Alberta DFOs use this approach, as does the AESO.[36]

55. FortisAlberta also stated that its objective is not to achieve any specific level of probabilistically-established reliability, either system-wide or for specific regions. Rather, it regularly analyzes its system to identify the consequences of component failures following possible contingency events, a deterministic exercise. FortisAlberta added that when those

34 Exhibit 23393-X0114, FortisAlberta Reply Submission, PDF page 8.
35 Exhibit 23393-X0052, Attachment-FortisAlberta letter to AESO, PDF pages 9 and 10.
36 Exhibit 23393-X0107, FortisAlberta Information, PDF pages 11 and 12.

consequences fail to satisfy standard well-accepted planning criteria shared by industry peers, it initiates a power system reinforcement project.

56. FortisAlberta stated that Aura's assertion incorrectly declares that a deterministic approach to load forecasting leads to over-prediction of unsupplied load. Rather, deterministic planning simply identifies unsupplied load, through detailed system modelling and load studies, that could occur when, and not if, an N-1 contingency occurs. For customers not directly connected to a faulted component, FortisAlberta argued that a deterministic planning approach would not allow these customers to go unserved, as would a probabilistic planning approach. FortisAlberta submitted that the following quote from Aura exemplifies why it adopted a deterministic approach:

> … the difficulty with reliability planning is that it is hard to predict when the random outcome will happen and how large the unsupplied load will be because that depends on what the load is at the time of [transformer] failure.[37]

57. FortisAlberta stated that when a system failure occurs, whether predictable or not, a deterministic approach ensures that the system has the requisite capability to restore service in the most efficient manner possible. FortisAlberta stated that this is the essence of FortisAlberta's distribution planning criteria and Good Utility Practice.

58. In response to Aura's statement that FortisAlberta "acknowledges there is value in applying probabilistic methods for N-2 contingency planning," FortisAlberta stated:

> The question is not whether probabilistic methods have merit in any circumstances; it is whether these methods represent a demonstrably superior means of planning in the development of the Alberta Interconnected Electric System (AIES); the Company submits that they do not.[38]

59. In response to Aura's view that "FortisAlberta would be able to meet its load requirements 99.99% of the time without making any facility modifications or additions,"[39] FortisAlberta argued that Aura's analysis is problematic. FortisAlberta explained that Aura's probabilistic analysis underestimated the level and magnitude of unsupplied load in the Fincastle area for the following reasons: (i) Aura only considered one specific cause of possible outages; (ii) it relied on an erroneous assumption that backup capability during peak loading would be available at all points in time; (iii) it did not use actual peak load values (contrary to Good Utility Practice); and (iv) it failed to identify localized supplied load. FortisAlberta argued that ironically, Aura's own evidence showed that unsupplied load is greater than zero.[40]

60. With regard to Aura's probabilistic modelling of the Hull 257S Substation and its claim that the 14.9-MW substation capacity would remain unused, FortisAlberta noted that this would only be under normal system configuration based on a predicted peak of 27.1 MW. FortisAlberta stated that Aura did not consider the need for capacity under N-1 contingencies.

37 Exhibit 23393-X0111, Final Argument Aura Power, paragraph 21.
38 Exhibit 23393-X0114, FortisAlberta Reply Submission, PDF page 6.
39 Exhibit 23393-X0099, Aura Power Renewables Ltd. Written Evidence, paragraphs 10 and 17.
40 Exhibit 23393-X0110, FortisAlberta Submission, Figure 1, PDF pages 12 and 13.

61. Finally, FortisAlberta argued that its electric distribution planning criteria and deterministic approach are used to facilitate restoration pending the completion of repairs following an event and constitute important aspects of FortisAlberta's overall approach to distribution management. FortisAlberta submitted that an unsubstantiated reduction of distribution system planning criteria and a switch to probabilistic distribution system planning for N-1 contingencies to delay currently required reliability upgrades would not be acceptable from an engineering perspective and generally would not accord with Good Utility Practice.[41]

3.2 The AESO's role as a transmission system planner

3.2.1 Views of Aura

62. Aura raised concerns that the AESO is not fulfilling its role as a transmission system planner, citing the AESO's duty under Section 29 of the *Electric Utilities Act* to provide system access service in a manner that gives all market participants wishing to exchange electric energy and ancillary services "a reasonable opportunity to do so." Aura's position is that the proposed system upgrade goes beyond the AESO's duty to provide reasonable system access service as it exacerbates high system access costs, jeopardizing the ability of market participants to access the interconnected electric system on reasonable terms.[42]

63. Aura submitted that the AESO's duty under Section 29 of the *Electric Utilities Act* is not unlimited. Rather, it is limited to providing *reasonable* access. For this reason, the Commission has consistently held that the legislation does not confer explicit or implicit transmission rights on market participants.[43] In Aura's view, FortisAlberta would be able to meet its load requirements 99.99 per cent of the time without making any facility modifications or additions,[44] and when subjected to a simple cost-benefit analysis, the extremely modest benefit of addressing the perceived N-1 unsupplied load is unjustified from a cost perspective.[45] Aura submitted that the AESO has satisfied its duty to provide FortisAlberta with reasonable system access service, and that FortisAlberta's SASR seeks access beyond what is reasonable in the circumstances.[46]

64. Aura submitted that the AESO has not properly scrutinized FortisAlberta's need assessment, conducted a cost-benefit analysis or considered feasible alternatives, which is inconsistent with the AESO's duty to exercise its functions in a responsible manner and provide for the economic operation of the interconnected electric system.[47]

65. Aura argued that FortisAlberta's determination that a deficiency exists such that additions to the distribution and transmission system are required is fundamental to the proposal before the Commission.[48] In contrast to system enhancements that the AESO finds to be needed for

41 Exhibit 23393-X007, FortisAlberta Information, PDF pages 12 and 13.
42 Exhibit 23393-X0111, Final Argument of Aura Power, paragraph 46, PDF page 15.
43 Exhibit 23393-X0111, Final Argument of Aura Power, paragraph 11, PDF page 5, citing Decision 2009-042, Alberta Electric System Operator Objections to ISO Rule 9.4 Transmission Constraints Management, April 9, 2009; Decision 2013-025, Alberta Electric System Operator Objections to ISO rules Section 203.6. Available Transfer Capability and Transfer Path, February 1, 2013; Decision 2014-242, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, August 21, 2014.
44 Exhibit 23393-X0099, Aura Written Evidence, paragraph 17, PDF pages 13 and 14.
45 Exhibit 23393-X0099, Aura Written Evidence, paragraph 9, PDF page 7.
46 Exhibit 23393-X0111, Final Argument of Aura Power, paragraph 12, PDF page 6.
47 Exhibit 23393-X0111, Final Argument of Aura Power, paragraph 46, PDF pages 15 and 16.
48 Exhibit 23393-X0115, Reply Argument of Aura Power, paragraph 11, PDF page 5.

reliability purposes, Aura stated that the proposed system upgrade would be a participant-related cost under the ISO tariff and would be paid for by FortisAlberta as the party requesting system access service. As a result, the need for the system upgrade is driven solely by FortisAlberta's application of its planning criteria.[49] Aura argued that while the AESO considers it overreaching to second-guess FortisAlberta's distribution planning decisions,[50] it implies that the Commission ought to be limited in its public interest assessment to considering only whether the AESO followed standard practices in responding to the SASR even if the underlying basis for the SASR is fundamentally flawed.[51] This would be inconsistent with the Commission's obligation to make decisions on transmission facility additions in a manner that is consistent with the public interest.[52]

66. Aura submitted that the AESO did not actively participate in finding the lowest cost solution to a need in an area where the solution could be provided, at least in part, by voluntary load-shedding or by using other non-wires alternatives.[53] Neither FortisAlberta nor the AESO provided any evidence to suggest they considered non-wires alternatives to the proposed system upgrade.[54] Accordingly, Aura requested the Commission to direct that future applications for transmission facility improvements in the Taber area include a cost-benefit analysis and an examination of non-wires solutions.[55]

3.2.2 Views of the AESO and FortisAlberta

67. The AESO argued that Aura's assertion that the AESO did not review the merits of FortisAlberta's SASR[56] is incorrect and unsupported.[57] The AESO satisfied its legislative mandate by following its established SASR review process, which included an independent and thorough review of the SASR and accompanying need for development report. This review ascertained the nature of the distribution deficiency and ensured the DFO considered and evaluated distribution options to meet the distribution deficiency before requesting a transmission solution.[58] The AESO noted that following its initial review and efforts to identify the best option to address the deficiency, it sought additional information from FortisAlberta which led to an updated SASR and need for development report being submitted prior to acceptance.[59]

68. In the AESO's view, it would be inconsistent with its statutory responsibilities to question FortisAlberta's reliability criteria used to determine the distribution deficiency leading to the SASR.[60] The AESO stated that the scope of its SASR review is to assess the information provide by the DFO that articulates the distribution deficiency. FortisAlberta stated that the

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49 Exhibit 23393-X0115, Reply Argument of Aura Power, paragraphs 10 and 11, PDF page 5.
50 Exhibit 23393-X0109, AESO Written Argument, paragraph 29, PDF pages 8 and 9.
51 Exhibit 23393-X0115, Reply Argument of Aura Power, paragraph 11, PDF page 5.
52 Exhibit 23393-X0115, Reply Argument of Aura Power, paragraph 11, PDF page 5.
53 Exhibit 23393-X0111, Final Argument of Aura Power, paragraph 39, PDF pages 13 and 14; Exhibit 23393-X0099, Aura Written Evidence, paragraphs 28, 31, PDF pages 19-21.
54 Exhibit 23393-X0111, Final Argument of Aura Power, paragraph 38, PDF page 13.
55 Exhibit 23393-X0099, Aura Written Evidence, paragraph 34, PDF page 23.
56 Exhibit 23393-X0099, Aura Written Evidence, paragraphs 24-25, 34, PDF pages 16-17, 23.
57 Exhibit 23393-X0109, AESO Written Argument, paragraph 25, PDF page 8.
58 Exhibit 23393-X0106, AESO Rebuttal Evidence, paragraphs A5 – A6, PDF pages 4-6.
59 Exhibit 23393-X0106, AESO Rebuttal Evidence, paragraph A6, PDF page 4 and 5.
60 Exhibit 23393-X0109, AESO Written Argument, paragraph 29, PDF page 8.

AESO does not oversee distribution planning; rather, the AESO relies on FortisAlberta to exercise and execute its statutory obligations to identify and evaluate deficiencies on the distribution system and propose solutions that may alleviate those deficiencies.[61] The AESO submitted that the purpose of its review is to ascertain the nature of the distribution deficiency and to understand the best options to address that deficiency.[62] The AESO argued that "[i]t would be overreaching for the AESO to second-guess the DFO's distribution planning decisions and forecasts in support thereof."[63]

69. The AESO submitted that this issue has been raised by other interveners in previous NID proceedings for connection projects in which the AESO's applications have been approved.[64] The AESO submitted that its assessment of the merits of the SASR in this case is reasonable and supported by prior Commission decisions wherein NID applications were approved.[65] This includes the Commission's findings in Decision 21973-D01-2017 wherein NID and facility applications for the Chestermere 419S Substation and Balzac 391S Substation modifications were approved, and Decision 22244-D01-2018 wherein the Anthony Henday 309S Substation was approved. These decisions are cited below, respectively:

> With respect to the issue of whether the AESO sufficiently scrutinized Fortis' planning decisions, the Commission finds that the UCA has not demonstrated that approval of the needs application would not be in the public interest. As the AESO stated in the hearing, its position is that it should not second-guess distribution facility owners' planning decisions, but that the AESO is nonetheless responsible for determining if upgrades to the transmission system are required. When the AESO receives a system access service request, it reviews the request and the need for development report to identify whether there are existing criteria violations or capacity concerns, and what solutions may address those concerns. In this case, the AESO reviewed four alternative solutions provided by Fortis[Alberta] prior to filing the needs identification document, one of which was a distribution solution, and concluded that only one of the alternatives warranted further consideration. The AESO further stated that while it does not independently test the distribution facility owner's load forecast values during this process, it does consider whether the values provided look reasonable and may ask the distribution facility owner questions to confirm that the information provided is realistic.[66]
>
> …
>
> As a DFO, FortisAlberta is obligated to comply with its statutory obligations, including its duties under Section 105(1)(b) of the *Electric Utilities Act* to "make decisions about building, upgrading or improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy." The Commission acknowledges the AESO's argument that it reviews and raises questions in respect of the forecasts provided by a DFO, in order to ascertain the nature of the need and the best option to address that need. When connecting a customer to the Alberta Interconnected

61 Exhibit 23393-X0106, AESO Rebuttal Evidence, paragraph A3, PDF page 3.
62 Exhibit 23393-X0106, AESO Rebuttal Evidence, paragraph A5, PDF page 4.
63 Exhibit 23393-X0109, AESO Written Argument, paragraph 29, PDF page 9.
64 Exhibit 23393-X0113, AESO Reply Argument, paragraph 21, PDF page 7.
65 Exhibit 23393-X0113, AESO Reply Argument, paragraph 21, PDF page 7.
66 Decision 21973-D01-2017: Alberta Electric System Operator – Chestermere 419S Substation and Balzac 391S Substation Modification Needs Identification Document Application, AltaLink Management Ltd. – Chestermere 419S Substation and Interconnection Facility Applications, Proceeding 21973, May 26, 2017, paragraph 90.

> Electric System, there may be a number of technical options that have varying degrees of transmission and distribution components. Given the legislative mandate of the AESO which includes acting in the public interest, the Commission is of the view that the AESO has the responsibility to determine, in consultation with the DFO, what technical solution is preferable to meet the need identified.[67]

70. The AESO submitted that Aura has not demonstrated that the approval of the application would be contrary to the public interest.[68] While Aura argues that FortisAlberta's SASR seeks access beyond what is reasonable,[69] in the AESO's view, it cannot ignore the SASR or provide a connection or enhancement to the transmission system that does not reasonably address the nature and scope of the SASR.[70] To do so would not provide any opportunity, let alone a reasonable opportunity, to exchange electric energy and ancillary services as required by Section 29 of the *Electric Utilities Act.*[71]

71. The AESO also disagreed with Aura's assertion that it is responsible for performing a cost-benefit analysis. As detailed below, in the AESO's view, performing a cost-benefit analysis in the manner suggested by Aura is not a requirement under Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* nor is there Commission guidance in NID decisions to suggest such a requirement.[72]

3.3 Cost-benefit analysis

3.3.1 Views of Aura

72. Aura stated that the Commission has previously recognized that the "public interest" cannot be universally defined, and that the ultimate determination of whether a project is in the "public interest" would largely be dictated by the circumstances of the particular application. Aura added that the assessment of the public interest requires the Commission to balance the benefits associated with upgrades to the transmission system with the associated impacts, having regard to the legislative framework for transmission development in Alberta. This approach is consistent with the well-established principle that a public interest assessment requires the Commission to balance the costs and benefits associated with a given proposal.[73]

73. Aura submitted that the economic effects of the project are properly before the Commission, and a cost-benefit analysis is required to ensure the Commission's decision on the application is consistent with the public interest. Aura argued that based on responses from FortisAlberta and the AESO to Aura's information requests,[74] neither the AESO nor FortisAlberta

[67] Decision 22244-D01-2018: Alberta Electric System Operator – Needs Identification Document Application; AltaLink Management Ltd. – Facility Applications, Anthony Henday 309S Substation, Proceeding 22244, February 7, 2018, paragraph 159.

[68] Exhibit 23393-X0113, AESO Reply Argument, paragraph 29, PDF page 8.

[69] Exhibit 23393-X0111, Final Argument of Aura Power, paragraph 12, PDF page 6.

[70] Exhibit 23393-X0113, AESO Reply Argument, paragraph 22, PDF page 7.

[71] Exhibit 23393-X0113, AESO Reply Argument, paragraph 22, PDF page 7.

[72] Exhibit 23393-X0113, AESO Reply Argument, paragraph 10 – 11, PDF page 4.

[73] Exhibit 23393-X0111, Final Argument of Aura Power, citing EUB Decision 2001-111: EPCOR Generation Inc. and EPCOR Power Development Corporation – 490 - MW Genesee Power Plant Expansion, Application 2001173, December 2001, paragraph 21; Decision 22966-D01-2018: BHEC-RES Alberta G.P. Inc., Forty Mile Wind Power Project, August 30, 2018, paragraphs 23 and 24.

[74] Exhibit 23393-X0099, Aura Written Evidence, PDF pages 15-17.

conducted a cost-benefit analysis to justify the proposed expenditure on system additions to determine whether it was in the public interest to proceed. Aura submitted that this evaluation falls to the Commission. Aura submitted that bypassing a cost-benefit analysis avoids any meaningful cost control measures for system additions, which are required to protect the public's interest in reasonable and economic access to the Alberta Interconnected Electric System.

74. Aura submitted that the AESO does not attempt to characterize or describe the benefit of the project and associated distribution additions beyond stating that it satisfies FortisAlberta's SASR. Aura added that FortisAlberta's position is essentially that the benefit cannot be quantified, and that ensuring compliance with its distribution planning criteria is implicitly beneficial to customers as it ensures reliable service. Aura submitted that although FortisAlberta criticized some of its calculations in its submissions, it was unsuccessful in identifying any material gaps and, importantly, it provided no alternative metric to present the reliability benefit gained by the proposed project and associated distribution additions.

75. Aura estimated that based on 2017 demand levels, the unsupplied load for all causes would be reduced by 0.3 per cent as a result of the project.[75] In response to FortisAlberta's claim that Aura underestimated the impact by 4.5 times due to outages caused by failures of subcomponents in substations, Aura argued that FortisAlberta failed to mention or account for the fact that subcomponent outages are of much shorter duration.

76. Aura claimed that based on the statistical analysis and data supplied by FortisAlberta and AltaLink, the project would increase overall reliability in the area by 0.0008 per cent. Aura indicated that although FortisAlberta challenged this calculation, it provided no alternative assessment of the quantitative benefits attributable to the project and associated distribution additions. Aura submitted that even at an order-of-magnitude level of assessment, the benefit of the project and the reliability improvement are minuscule for the project cost estimate.

77. Rather than provide a quantitative assessment of the benefit, FortisAlberta applied a uniform planning standard and made its determination on that basis alone. Aura added that this approach would result in decisions based entirely on hypothetical scenarios that need not reflect reality. While FortisAlberta relied on Good Utility Practice to defend its assessment, Aura argued that such a standard is largely subjective and has the potential to promote continued bad practices that are contrary to the public interest. Good Utility Practice is not an excuse to make decisions that run contrary to the legislative scheme and the public interest.

78. Aura submitted that both the AESO and FortisAlberta cite the legislative requirement under Subsection 105(1)(b) of the *Electric Utilities Act* to indicate that FortisAlberta makes decisions about upgrading the distribution system in a manner that provides for the economic delivery of electricity to consumers. However, neither party explained how, if approved, the project would result in an economically efficient outcome. Aura added that the AESO and FortisAlberta "essentially skipped over that step, focusing solely on reliability standards" and that similarly neither party "explained how the proposed System Upgrade is consistent with the AESO's duty to ensure economic operation of the interconnected electric system."[76]

75 Exhibit 23393-X0099, Aura Written Evidence, paragraph 19.
76 Exhibit 23393-X0115, Reply Argument of Aura Power, PDF page 9.

79. In response to FortisAlberta's suggestion that its expenditures on the project and associated distribution works would not lead directly to higher rates for customers due to the mechanics of the performance-based regulation (PBR) regime, Aura argued that PBR is simply a rate-setting mechanism and does not prevent capital expenditures from ending up in the rate base, and therefore, on customers' bills. Further, Aura noted that under the PBR regime, the revenue requirement associated with capital expenditures can, in certain cases, be recovered outside of the I-X mechanism through a K factor adjustment. As a result, "[a]s capital expenditures increase, the next generation PBR will also eventually result in higher rates to consumers, as the same guiding principles of the 2013-2017 PBR will apply."[77]

80. Simply put, Aura's position is that where the cost to implement reliability enhancements is proportionate to the reliability benefit, the work is likely justified in the circumstances and in the public interest. Aura added that the converse is also true: "where the costs are significant and the reliability improvement is miniscule, then it does not make sense to proceed, and other measures should be considered, such as ensuring proper operations and maintenance practices to minimize the risk of equipment failures and ensuring sufficient contingency plans, such as through providing backup power sources, are in place." Aura submitted that "nonwires solutions may also be a cost-effective method to address potential outage risks."[78]

3.3.2 Views of the AESO and FortisAlberta

81. In reply, the AESO explained how it considered the costs of the project as part of the alternative selection process. The AESO stated that its application meets the Commission's Rule 007 requirements for NID applications. The AESO provided the following responses to Aura's suggestion to provide a cost-benefit analysis:

- Performing the cost-benefit analysis in the manner suggested by Aura is not a requirement under AUC Rule 007 and, as such, the AESO has not done a cost-benefit analysis in this case.
- Given the requirements of AUC Rule 007 and in the absence of guidance from the Commission in needs document decisions to suggest otherwise, it is not the AESO's practice to perform cost-benefit analysis in the manner suggested by Aura for needs identification document applications for system access service requests.
- The Commission decisions relied upon by Aura to support its cost-benefit argument are facility application decisions – not needs identification document decisions.
- Aura has provided no authority to suggest that a cost-benefit analysis is required or should be considered as part of the Commission's public interest assessment of a needs identification document application.[79]

[77] Exhibit 23393-X0115, Reply Argument of Aura Power, PDF pages 8 and 9.
[78] Exhibit 23393-X0115, Reply Argument of Aura Power, PDF page 9.
[79] Exhibit 23393-X0113, AESO Reply Argument, PDF pages 4 and 5.

82. The AESO indicated that the decisions cited by Aura in support of its cost-benefit argument deal with facility applications, not NID applications. Further, the AESO stated that in the Chestermere NID and facility proceeding (Proceeding 21973), the Utilities Consumer Advocate (UCA) raised similar concerns about minimizing the cost of FortisAlberta's capital assets, which were addressed in the Commission's findings:

> 93. …Generally speaking, it is the Commission's expectation that transitioning away from the existing capital tracker mechanism with its cost-of service regulation features, will reduce the incentive for a utility to increase its rate base. In this proceeding, construction of the proposed substation is expected to start in April 2018. Therefore, the Commission considers that the UCA's concern with Fortis' incentive structure will most likely be mitigated in this case because the project will be put into service in 2018, when the next generation of performance-based regulation comes into effect.
>
> 94. As a distribution facility owner, Fortis is obligated to comply with its statutory obligations, including its duties under Section 105(1)(b) of the *Electric Utilities Act* to "make decisions about building, upgrading or improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy." The Commission agrees with the UCA's assertion that this duty can be subject to questioning and oversight. However, in this case, given the oversight provided in the capital tracker true-up process and the effect of transitioning to expected stronger incentives under the next generation of performance-based regulation, the Commission accepts the AESO's conclusion that the project is in the public interest. However, as they apply more generally, these matters may be part of the Commission's review of AESO tariff contribution policy provisions in a future AESO tariff proceeding.[80]

83. Lastly, the AESO concluded that the purpose of this proceeding is only to determine the need for the preferred transmission development to address the SASR, and that there are separate means through which Aura could raise its concerns, as recognized by the Commission in its standing decision.[81]

84. In its reply, FortisAlberta stated that while it agreed with Aura that the public interest test could not be conclusively defined, Aura's argument oversimplifies the public interest analysis required to be completed by the Commission in this case. FortisAlberta submitted that a proper assessment of the public interest test in assessing reliability-driven projects could not simply amount to the assignment of a notional "unit cost" of benefit followed by a comparison to the cost associated with maintaining the status quo (i.e., the cost of doing nothing). FortisAlberta argued that such an approach is overly reductionist; in the near term, choosing to do nothing may always appear to be the most economic and cost-effective option.

85. FortisAlberta argued that aside from the fact that Aura's calculations to obtain an artificial unit cost rely upon incomplete and inaccurate data sets and calculation methodology, Aura's approach ignores the holistic system benefits to the Fincastle area. FortisAlberta added that these benefits, which could not be monetized in the manner suggested by Aura, include increased overall operational flexibility and more system alternatives in the event of contingency events that would reduce total outage times.

80 Decision 21973-D01-2017, paragraphs 93 and 94.
81 Exhibit 23393-X0044, AUC Ruling on Aura Power Renewables Ltd. standing and motion.

86. FortisAlberta disputed Aura's assertion that FortisAlberta considers that the "public interest is served by any reliability improvement at any cost." FortisAlberta argued that Aura took its information request response out of context when FortisAlberta was asked if it set monetary limits on reliability projects. FortisAlberta explained that any specific monetary threshold would be arbitrary and would not recognize the specifics of each project, therefore resulting in inequitable treatment of its customers. FortisAlberta clarified that it does not consider that necessary reliability-driven work could be delayed indefinitely or cancelled purely because its completion would require costs to be incurred. FortisAlberta stated that although there is no set dollar value threshold for reliability projects, the Commission may fairly appreciate FortisAlberta's own distribution system planning criteria as constituting a means of cost control:

> The Company's planning criteria specifically prescribe restoration capability in the event of an N-1 contingency. They do not encourage, or otherwise support the implementation of solutions that would provide excessive backup or other forms of overbuilding (e.g., the implementation of solutions that would be designed to address N-2 contingencies on a deterministic basis).[82]

87. FortisAlberta stated that it did not undertake reliability projects in a "cost-insensitive" manner and that the evidence shows the opposite. It submitted that through the AESO's connection process, it reviewed various alternative solutions and abandoned those that were less cost-effective.

88. In response to Aura's submission that there should be cost-benefit criteria for approval of reliability projects due to ratepayer impacts, FortisAlberta submitted that any indicated growth in FortisAlberta's rate base "is not directly correlated with the amount of capital expenditure undertaken on account of solely customer load." FortisAlberta submitted that "Aura's suggestion that increased rate base leads directly to higher rates fails to appreciate the mechanics of the Commission's performance-based regulation (PBR) regime."[83]

89. FortisAlberta also submitted that Aura's evidence that the total cost of the project is $28.5 million is derived from selectively inflating the project's and distribution system upgrade costs to the upper bounds of the accuracy range. Instead, the costs of implementing the project are estimated to be $6 million. This expenditure would reduce unsupplied load resulting from N-1 contingency events at the Fincastle 336S Substation POD by 8.2 MVA, with minimal upgrading of the local distribution system. FortisAlberta stated that the completion of a further subset of the proposed associated distribution system upgrades, which have an estimated cost of $9.7 million, would reduce the total Fincastle area POD unsupplied load by a further 10.6 MVA, bringing unsupplied load resulting from N-1 contingency events in the affected area POD substations to 0 MVA. FortisAlberta submitted that consequently, the correct estimated cost to completely resolve the identified unsupplied load is $15.7 million (i.e., the sum of the transmission-associated costs ($6 million)[84] and distribution-associated costs ($9.7 million)) and not $28.5 million, as suggested by Aura.[85]

82 Exhibit 23393-X0114, FortisAlberta Reply Submission, PDF page 6.
83 Exhibit 23393-X0110, 2018-11-14 FortisAlberta Submission to AESO Proceeding 23393, paragraph 21.
84 Six million dollars is based on the AESO's estimate. AltaLink's estimate was $5,763,000.
85 Exhibit 23393-X0110, FortisAlberta Submission, PDF page 7.

3.4 Feasibility of Aura's load-shedding alternative

3.4.1 Views of Aura

90. Aura stated that neither FortisAlberta nor the AESO provided any evidence to suggest that they considered non-wires alternatives to the project. Given that the potential reliability improvement associated with mitigating a transformer outage is so minimal in this case, such a solution may not be warranted to address transformer outage risk. Aura submitted that it is appropriate for DFOs such as FortisAlberta to consider non-wires options to address reliability concerns as alternatives to expensive system builds. Aura submitted it is in the public interest to implement such options to the extent that they are feasible, achieve the same or better reliability benefit as a system improvement, and come at a much lower cost.

91. Aura stated that its written evidence confirmed that a voluntary load-shedding program is feasible in this case, and argued that had the AESO or FortisAlberta seriously examined non-wires alternatives, they would have found significantly less costly options than the transmission alternatives considered.

92. Aura argued that the implementation of a load-shedding program would be considerably less costly than the project. Aura provided a rough estimate of the level of compensation that could be required for a load-shedding program using the compensation structure for the AESO's Load Shed Service for imports program as a template. Aura stated that if it assumed an unsupplied load of 57 MWh over a 10-year period as determined by Aura's probabilistic modelling, the total compensation that would be required in a load-shedding program to shed this amount of load over the time period is estimated to be a little over $60,000. Aura claimed that this amount of compensation is miniscule compared to the $28 million investment required for the project.[86]

93. Aura also conducted a telephone survey on the willingness to participate in such a load-shedding program with 18 companies. Ten companies responded, nine of them indicating that they would be willing to consider it.

94. In response to FortisAlberta's statement that "Aura's suggested solution for implementation by FortisAlberta to mitigate unsupplied load is to essentially do nothing," Aura argued that this is an inaccurate characterization of its evidence. Aura submitted that it has demonstrated that the amount of unsupplied load that would be realistically addressed by the project is so minimal as to be imperceptible. Further, FortisAlberta and AltaLink have capabilities and plans to mitigate the impact of potential equipment failures, such as through the use of AltaLink's mobile transformers. Lastly, part of the relief that Aura is requesting from the Commission in this proceeding is to direct the AESO to consider less expensive alternatives to address the perceived N-1 unsupplied load, such as through a voluntary load-shedding program.

3.4.2 Views of FortisAlberta

95. With respect to Aura's proposed non-wires solution, FortisAlberta stated that Aura's suggestion of using the AESO's Load Shed Service for import program as a template for a non-wires alternative would be problematic. FortisAlberta explained that the AESO's Load Shed Service for imports program is a means of addressing supply-related unsupplied load concerns arising from the AESO's efforts to fulfill its intertie restoration obligation, as mandated by

[86] Exhibit 23393-X0099, Aura Written Evidence, PDF page 22.

legislation. However, FortisAlberta added that the project is required to address delivery-related unsupplied load to ensure the delivery of adequate energy to the end-use customer.

96. FortisAlberta indicated that a load-shedding type program would not be possible under its Commission-approved distribution tariff and the applicable legislative framework. It explained that the program would require some of its customers to curtail load, essentially foregoing their entitlement to reliable service. Further, FortisAlberta argued that the program would require mandatory involvement at a local level, which in turn, would cause inequitable service to those in affected areas and therefore be contrary to FortisAlberta's statutory duty under the *Electric Utilities Act*. FortisAlberta added that it would also be contrary to FortisAlberta's contractual obligation to its customers to reserve or allocate certain capacity for customer-committed loads.[87]

97. FortisAlberta stated that Aura's cost comparison between an overstated upper limit estimated cost of the project plus distribution upgrades against an understated and unrealistic cost ($60,000)[88] to implement a non-wires solution is misguided. FortisAlberta added that Aura completely disregarded any costs related to establishing and implementing such a program. FortisAlberta also submitted that Aura's proposed load-shedding program is untested and would require considerable examination, comprehensive stakeholder input, and revision to existing tariffs, and that these activities would all have to be done at the expense of Alberta taxpayers.[89]

98. Further, FortisAlberta added that while Aura continued to maintain that a load-shedding program would stand up as a superior option to the project, it erroneously maintained that such a program could be carried out on a strictly voluntary basis. FortisAlberta explained that if such an approach were implemented, the physical characteristics of the system would dictate that certain customers would be forced to participate in a load-shedding program by virtue of their location relative to other customers who may volunteer. For example, "customers located on the end of any radial line or customers where the distribution system characteristics do not allow for adequate quality power to be supplied from distant backup POD substations would be automatically forced to submit to load-shedding simply by virtue of their location." FortisAlberta commented that Aura's proposal was "notably silent regarding whether and how suitable compensation would be provided to any such customers subjected to forced load-shedding of this kind."[90]

99. Finally, in response to Aura's argument that using AltaLink's mobile transformers would be a superior option to the proposed transmission development, FortisAlberta argued that mobile transformers do not provide a reasonable or timely solution to N-1 contingencies. FortisAlberta explained that mobilizing and connecting those transformers can take from 24 to 72 hours, depending on the location of the nearest appropriate mobile substation. The timing for deployment could also be "extended by the number of mobile transformers available and the amount of qualified personnel to deploy same at the time of the N-1 contingency event", or weather conditions or other transport restrictions. FortisAlberta submitted that "these realities substantially, if not totally, nullify the suitability of this proposed alternative to the [proposed transmission development]."[91]

87 Exhibit 23393-X0110, FortisAlberta Submission, PDF page 17.
88 Exhibit 23393-X0099, Aura Written Evidence, PDF page 22.
89 Exhibit 23393-X0110, FortisAlberta Submission, PDF page 18.
90 Exhibit 23393-X0114, FortisAlberta Reply Submission, PDF page 10.
91 Exhibit 23393-X0114, FortisAlberta Reply Submission, PDF page 11.

3.5 Findings of the majority

100. The AESO is responsible under the *Electric Utilities Act* and the *Transmission Regulation* to plan a flexible and forward-looking transmission system, and reasonably anticipate load increases and new generation. The AESO is also required by Section 29 of the *Electric Utilities Act* to provide system access service in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so. The majority finds that in these circumstances, the AESO fulfilled its responsibilities in its consideration of, and proposed solution to address, the SASR submitted by FortisAlberta.

101. The majority finds that the AESO's NID application contains all the information required by the *Electric Utilities Act*, the *Transmission Regulation* and Rule 007.

102. Having considered all of the evidence before it, for the reasons that follow, the majority finds that no interested person has demonstrated that the AESO's assessment of the need for the proposed development is technically deficient or that approval of the NID application is not in the public interest. Therefore, the majority considers the AESO's assessment of the need to be correct, in accordance with Subsection 38(e) of the *Transmission Regulation*, and approves the AESO's NID application.

3.5.1 Load forecasts

103. As noted above, the NID in this proceeding arises from FortisAlberta's request for system access service to reliably serve load growth in the Taber area. Aura raised two primary and interrelated concerns with the underlying need for the project identified by FortisAlberta: (i) that its forecast peak loads are consistently higher than actuals; and (ii) that its deterministic approach to identifying unsupplied loads during N-1 contingencies overstates the potential unsupplied load.

104. First, Aura raised concerns that FortisAlberta's forecast of substation peak loads is consistently higher than actual peak loads. The majority observes that there were three load forecasts developed or updated by FortisAlberta, on December 6, 2016,[92] September 18, 2017,[93] and April 16, 2018,[94] respectively. FortisAlberta predicted that the peak load at the Fincastle 336S Substation would be 17.9 MVA in 2016 while the actual recorded peak load was 17.1 MVA. FortisAlberta predicted the peak load at the Fincastle 336S Substation would be 18.0 MVA in 2017, which was updated to 17.9 MVA on September 18, 2017, while the actual recorded peak load was 19.1 MVA. Therefore, the majority does not agree with Aura's argument that FortisAlberta's forecast of substation peak loads is consistently higher than actual peak loads, based on the forecast and actual loads at the Fincastle 336S Substation in 2016 and 2017.

105. The majority observes that although there are some discrepancies between predicted load and actual load at substations in the Taber area, the total area load was recorded as 145.2 MVA in 2017, while the predicted area load for 2017 was 152.2 MVA. The majority also observes that

[92] Exhibit 23393-X0007, Appendix E - DFO Need for Development Report, PDF page 9, Table 3-1: FortisAlberta Load Forecast: Existing System.

[93] Exhibit 23393-X0007, Appendix E - DFO Need for Development Report, PDF page 26, Table 3-1: FortisAlberta Load Forecast: Existing System.

[94] Exhibit 23393-X0038, 2018-04-16 FortisAlberta Letter to AESO Proceeding 23393, PDF page 3, Updated Table 4-1: FortisAlberta Historic and Forecast Load: Existing System.

the actual area load had increased from 124.4 MVA in 2016 to 145.2 MVA in 2017, representing 17 per cent growth.

106. The majority acknowledges that FortisAlberta applied coincident factors to committed customer loads, feeders, transformers and substations in its load forecasting. The majority is convinced that FortisAlberta did not simply sum the historical peak load or contracted committed load for each individual user without any consideration for their coincidence.

107. The majority observes that FortisAlberta predicted that the unserved load in 2026 would be 15.8 MVA.[95] However, because the predicted load in 2026 in the most recent forecast[96] is higher than in the previous forecast, the majority anticipates that the unserved load in 2026 would likely be higher than 15.8 MVA.

108. The majority considers that the updated peak load information for 2016 and 2017 at the Fincastle 336S Substation validates FortisAlberta's forecasted peaks for that substation, which somewhat mitigates Aura's stated concerns with respect to FortisAlberta's forecasting methodology. The majority is not convinced that the variance between predicted and actual peak loads at the remaining area substations is, in itself, sufficient to demonstrate that the underlying need to upgrade the Fincastle 336S Substation does not exist or is overstated.

109. Second, Aura raised concerns with FortisAlberta's deterministic approach to identifying unsupplied loads. In response to Aura's submission that a probabilistic approach provides reasonable expected values for unsupplied load (if any), FortisAlberta submitted that its deterministic modelling approach is used by other DFOs in Alberta and follows Good Utility Practice. The majority notes that the Commission considered similar issues in Decision 23339-D01-2018[97] for the Provost Reliability Upgrade Project. Similar to the majority findings in that decision, the majority considers that this proceeding has provided greater insight into various aspects of SASRs submitted by DFOs driven by reliability concerns. However, the broader issue of whether, when and how utilities use probabilistic planning is a complex issue that the majority finds is beyond the scope of a single NID proceeding. The majority considers that value could nonetheless be added to future reliability-driven NID applications through provision of additional information on the merits of deterministic versus probabilistic analysis in the DFO's planning process, and whether and how the DFO takes those merits into account in system planning.

110. The majority considers that the same approach as considered in the Provost decision is reasonable here. While the complexity of the issues around whether DFOs should, more generally, use probabilistic or deterministic analysis in planning their systems is beyond the scope of a single proceeding, there is merit in exploring ways to add value to future reliability-driven NID applications through additional information on these planning considerations.

111. The majority has taken into account the foregoing in assessing the underlying need for the project as identified in FortisAlberta's SASR. However, the majority also notes that

95 Exhibit 23393-X0007, Appendix E - DFO Need for Development Report, PDF page 27.

96 Exhibit 23393-X0038, 2018-04-16 FortisAlberta Letter to AESO Proceeding 23393, PDF page 3, Updated Table 4-1: FortisAlberta Historic and Forecast Load: Existing System.

97 Decision 23339-D01-2019: Alberta Electric System Operator Needs Identification Document Application and AltaLink Management Ltd. Facility Applications – Provost Reliability Upgrade Project, Proceeding 23339, Applications 23339-A001 to 23339-A006, January 22, 2019.

FortisAlberta's evidence demonstrates that the project is not reliant on either deterministic or probabilistic load forecasting but based on actual metered feeder peak load levels. Given the presence of actual peak load which would go unsupplied in the event of an N-1 contingency, the majority is satisfied that FortisAlberta's load forecasting provides adequate justification for the need identified in its SASR.

3.5.2 The AESO's role and Aura's proposed cost-benefit analysis

112. Aura raised concerns in this proceeding regarding the costs of the project and its impact on ratepayers and on Aura's business. Essentially, Aura's argument is that the cost of any project should be proportionate to its benefits, and the AESO must accordingly perform a cost-benefit analysis in its NID applications. In support of its view that the project is not in the public interest, Aura filed calculations showing that the project provided minuscule reliability improvement when compared to overall project cost. Hence, in Aura's view, the benefit of the project is not proportionate to its cost. In contrast, the AESO asserted it is not within its mandate to provide a cost-benefit analysis of its need assessment. However, this does not mean the AESO did not choose the lowest cost alternative when it selected the project.

113. Pursuant to its responsibilities under Section 29 of the *Electric Utilities Act,* the AESO must provide system access service on the transmission system in a manner that gives all market participants (in this case a DFO), a reasonable opportunity to exchange electric energy and ancillary services. When the AESO receives a system access service request, it reviews the request and the need for development report to identify whether there are existing criteria violations or capacity concerns, and what solutions may address those concerns.

114. As a DFO, FortisAlberta is obligated to comply with its statutory obligations, including its duties under Section 105(1)(b) of the *Electric Utilities Act* to "make decisions about building, upgrading or improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy." DFOs are also responsible under the *Transmission Regulation* to assist the AESO in "preparing and evaluating needs identification documents" and to assist the AESO in "evaluating the relative merits of transmission and distribution options." Together, these obligations require a DFO to have regard for its duty to provide "safe, reliable and economic" service while assisting the AESO in preparing a NID.

115. In this case, the AESO submitted that the project is required to respond to FortisAlberta's request based on FortisAlberta's SASR and need for development report. The AESO explained that it conducted its review of the SASR and accompanying need for development report, and that it sought additional information from FortisAlberta following that review which led to the submission of an updated SASR and need for development report.[98] The evidence in this proceeding is that the AESO relied on FortisAlberta's evaluation of the distribution system as outlined in FortisAlberta's updated need for development report, which indicated that the alternative involving distribution system developments alone would be a significantly higher cost solution.[99]

116. The AESO explained that the public interest is engaged as part of its determination of the appropriate transmission development with which to respond to a SASR. This determination includes assessing the impact of the connection on transmission system performance,

98 Exhibit 23393-X0106, AESO Rebuttal Evidence, paragraph A6, PDF pages 4 to 6.
99 Exhibit 23393-X0007, Appendix E – DFO Need for Development Report.

determining how the estimated capital costs of the project would be classified, and considering the high-level environmental and land use effects of the examined transmission development option.[100] The majority accepts the AESO's detailed analysis and its assertion that Alternative 3, involving upgrades at both the Fincastle 336S and Hull 257S substations, is a more costly alternative than the project.

117. The majority is also satisfied with the AESO and FortisAlberta's explanation that Alternative 1, the distribution-only solution, would be significantly more costly than the alternatives. FortisAlberta argued that its SASR provided the lowest cost alternative to address its distribution deficiencies. It added that the benefits of reliability-driven projects such as the one proposed in this proceeding cannot be quantified, and that Aura ignored the holistic system benefits to the Fincastle area resulting from the project. The majority is satisfied with FortisAlberta's explanation that its SASR is the lowest cost alternative and provides broader system benefits.

118. The majority acknowledges the AESO's argument that it reviews and raises questions in respect of the forecasts provided by a DFO in order to ascertain the nature of the need and the best option to address that need. Based on the evidence before it, and having particular regard for the AESO's evidence that it reviewed and questioned FortisAlberta's SASR which resulted in the submission of an updated SASR and need for development report,[101] the majority considers that the AESO acted reasonably and consistently with its past practice in reviewing the need for the project. In conjunction with the oversight provided through the PBR framework governing the DFOs under its jurisdiction, including FortisAlberta, the majority finds that this overall review process allows the majority to adequately determine whether a proposed transmission development is in the public interest. In the Commission's Chestermere decision, as cited more recently in the Provost decision, the majority explained DFO oversight through PBR as follows:

> As a distribution facility owner, Fortis[Alberta] is obligated to comply with its statutory obligations, including its duties under Section 105(1)(b) of the Electric Utilities Act to "make decisions about building, upgrading or improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy." The Commission agrees with the UCA's assertion that this duty can be subject to questioning and oversight. However, in this case, given the oversight provided in the capital tracker true-up process and the effect of transitioning to expected stronger incentives under the next generation of performance-based regulation, the Commission accepts the AESO's conclusion that the project is in the public interest. However, as they apply more generally, these matters may be part of the Commission's review of AESO tariff contribution policy provisions in a future AESO tariff proceeding.[108]

119. Aura's arguments are largely true for the expenditures incurred under the capital tracker mechanism during the previous 2013-2017 PBR term for the DFOs. The majority considers that the approach to the separation of capital under the current generation PBR plan, in effect for the 2018-2022 term, ensures that the vast majority of capital will be subject to the incentives of PBR which are superior to those inherent in cost-of-service regulation.[109] The current generation PBR plan reduces the potential incentives associated with the capital tracker mechanism that was in place under the 2013-2017 PBR, for DFOs to undertake unnecessary capital investments to increase their rate base and returns. Under the provisions of the current generation PBR, the

[100] Exhibit 23393-X0106, AESO Rebuttal Evidence, paragraph A7, PDF pages 6 and 7.
[101] Exhibit 23393-X0106, AESO Rebuttal Evidence, PDF pages 5 and 6.

DFOs receive a predetermined amount of incremental capital funding for each year, based on the average of past expenditures. The DFOs then have the opportunity to choose how and where to spend that funding while providing safe and reliable service and meeting Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors requirements*. In the majority's view, the current generation PBR mitigates incentives for the DFOs to undertake unnecessary capital investments to increase their rate base and returns.

120. With respect to Aura's argument that capital expenditures incurred during the current PBR term will end up in the rate base and on customer's bills, the majority does not consider this to be a given outcome, as it will depend upon the method of rebasing chosen at the time of the next rebasing. For example, for the 2018-2022 PBR plans, the Commission did not rebase FortisAlberta on its actual 2017 costs for non-capital tracker projects, but rather, on the notional costs equal to the historical average of prior expenditures. The Commission may also conduct prudence reviews for the capital expenditures incurred during the 2018-2022 PBR, resulting in adjustments to the actual rate base.

121. Having regard to the foregoing, in the majority's view, the AESO acted within its mandate and in keeping with its statutory duties in preparing the NID application and identifying the preferable technical solution to meet the need identified. Considering the evidence before it with respect to the AESO's review process and the chosen alternative, the majority finds that the AESO's selection of its preferred transmission development is reasonable and in keeping with its statutory mandate.

3.5.3 Feasibility of Aura's load-shedding alternative

122. Aura proposed a voluntary load-shedding alternative (a non-wires solution) to the need identified by FortisAlberta's SASR. Aura estimated the cost of such a program to be slightly more than $60,000 over a 10-year period deriving from its probabilistic modelling and using the compensation structure for the AESO's Load Shed Service for imports program as a template.[102] As mentioned above, a broader issue of whether, when and how utilities use probabilistic planning is a complex issue that the majority finds is beyond the scope of a single NID proceeding.

123. Further, Aura appears to suggest that a voluntary load-shedding program would not have impacts on customers connected to the distribution system, while FortisAlberta argued the contrary. The majority notes that Aura has neither provided evidence that a voluntary load-shedding program would be widely accepted by the customers in the Taber area, nor presented solutions to continue to provide reliable electricity to customers who share the same feeder with those voluntarily participating in the program. The majority is not satisfied that Aura's survey of a limited number of customers' willingness to consider a voluntary load-shedding program is sufficient to demonstrate the feasibility of such a program.

124. Aura also proposed to use AltaLink's mobile transformers as a less expensive alternative to the project to address the N-1 unsupplied load. The majority finds that little information was provided by Aura as to how the mobile transformers at various locations (depending on the

[102] Exhibit 23393-X0099, Aura Written Evidence, paragraph 33.

nearest appropriate mobile substation) would be transported in a reasonable time to where they would be needed, and particularly under potential transportation and personnel restrictions.

125. Further, Section 15(3) of the *Transmission Regulation* sets constraints on when the AESO can make or provide for a non-wires solution. Specifically, it states:

> **(3)** In considering the design and planning of the transmission system, the ISO may make or provide for specific and limited exceptions to the requirements of subsection (1) and propose a non-wires solution
>
> (a) in areas where there is limited potential for growth of load, and the cost of the non-wires solution is materially less than the life-cycle cost of the transmission wires solution, compared over an equivalent study period, or
>
> (b) if the non-wires solution is required to ensure reliable service due to the shorter lead time of the non-wires solution, for a specified limited period of time.

126. The majority finds that Aura has not demonstrated that the conditions required under Section 15(3) for a non-wires solution have been met. The majority is not convinced that the evidence demonstrates that there is limited potential for load growth in the area, nor that Aura's non-wires solution is required to ensure reliable service due to a shorter lead time, for a specified limited period of time.

127. In the majority's view, Aura's suggested non-wires alternative has not been used in FortisAlberta's distribution planning to date, and Aura's assumption that customers would be willing to voluntarily participate in a load-shedding program was based on a small survey sample without wide stakeholder input. Further, the economic benefit of the load-shedding program was calculated from its probabilistic modelling and the compensation structure for the AESO's Load Shed Service for imports program, which is beyond the scope of this proceeding. As a result, the majority cannot conclude that a voluntary load-shedding alternative is feasible in the circumstances, nor that Aura's proposal is sufficient to demonstrate that the AESO's preferred alternative is technically deficient or that approval of the NID is not in the public interest.

4 Facility application

128. To meet the need identified by the AESO, AltaLink proposed to alter the Fincastle 336S Substation. The substation, operating pursuant to Permit and Licence U2006-250,[103] is located in the southwest quarter of Section 15, Township 10, Range 15, west of the Fourth Meridian. To meet the need identified by the AESO, AltaLink proposed the following alterations:

- adding one 138/25-kV, 15/20/25-MVA load tap change (LTC) transformer
- adding two 138-kV circuit breakers
- adding one new combined switchgear/control building containing four 25-kV circuit breakers
- removing associated minor substation equipment

[103] Substation Permit and Licence U2006-250, Application 1465406, October 10, 2006.

129. AltaLink also seeks approval to salvage associated minor substation equipment.[104]

130. AltaLink proposed to install a temporary bypass transmission line (approximately 25 metres) to connect the existing 607L and 610L transmission lines, bypassing the Fincastle 336S Substation. This temporary bypass transmission line would allow the radial 607L transmission line to remain energized during a 138-kV bus outage in order to install the new equipment. The temporary bypass transmission line would be removed once the 138-kV bus is returned to service.

131. AltaLink stated that FortisAlberta requested that no 25-kV load interruption occur during construction. Accordingly, a mobile substation is planned to be located inside the substation fence and would be used during construction.

132. AltaLink stated that there would be no fence expansion required for the Fincastle 336S Substation alterations. Construction activities would occur on land leased by AltaLink and access to the substation would be via the substation access road.

133. AltaLink's participant involvement program included notification to and consultation with landowners, agencies and industry. AltaLink stated it responded to concerns raised by landowners and occupants, and provided additional information and followed up with stakeholders. AltaLink submitted there are no outstanding public or industry objections or concerns.[105]

134. AltaLink expects the incremental visual impact of the project to be minimal. It added that there have been no significant viewpoints identified within the project area and that the nearest residence is approximately 450 metres southwest of the substation. AltaLink stated that during consultation, no stakeholders expressed concerns about potential visual impacts.

135. AltaLink committed to comply with the relevant sections of the Alberta *Environmental Protection and Enhancement Act*, the *Environmental Protection Guidelines for Transmission Lines*, and any other statutes, regulations, rules, and/or guidelines. Based on the scope of the project, and provided mitigation measures are implemented as outlined in its environmental specifications and requirements report,[106] AltaLink anticipates potential environmental effects to be negligible.

136. AltaLink received *Historical Resources Act* clearance for the project from Alberta Culture and Tourism.

137. The noise impact assessment conducted for the project predicted that the Fincastle 336S Substation would be in compliance with Rule 012: *Noise Control*.

138. AltaLink estimated the cost of the project to be approximately $5,763,000 (within plus 20 per cent and minus 10 per cent accuracy). There are no system costs, and the project cost would be allocated to FortisAlberta.

[104] AltaLink proposes to salvage an existing three-way 25-kV switch and a 138-kV T1 transformer motorized disconnect switch.
[105] Exhibit 23393-X0024, PDF page 2.
[106] Exhibit 23393-X0013, AML Fortis Fincastle Substation Upgrade - Appendix H Environmental Support.

139. AltaLink's proposed in-service date is June 1, 2019.

4.1 Findings of the majority

140. The majority finds that the facility application to alter the Fincastle 336S Substation, filed by AltaLink pursuant to sections 14 and 15 of the *Hydro and Electric Energy Act*, complies with the information requirements prescribed in Rule 007. The facility application is also consistent with the need identified in the NID application. The majority also finds that the joint participant involvement program undertaken by the AESO and AltaLink meets the requirements of Rule 007.

141. The majority is satisfied that there are no outstanding technical or environmental concerns associated with the project from parties with standing, nor are there any outstanding public or industry concerns.

142. Given the considerations discussed above, the majority finds the project to be in the public interest, pursuant to Section 17 of the *Alberta Utilities Commission Act.*

5 Decision

143. Pursuant to Section 34 of the *Electric Utilities Act*, the Commission approves the need outlined in Needs Identification Document Application 23393-A001 and grants the AESO the approval set out in Appendix 1 – Needs Identification Document Approval 23393-D02-2019.

144. Pursuant to sections 14, 15 and 19 of the *Hydro and Electric Energy Act*, the Commission approves Application 23393-A002 and grants AltaLink the approval set out in Appendix 2 – Substation Permit and Licence 23393-D03-2019 to alter and operate the Fincastle 336S Substation.

145. The appendixes will be distributed separately.

Dated on February 14, 2019.

Alberta Utilities Commission

(*original signed by*)

Neil Jamieson
Commission Member

(*original signed by*)

Joanne Phillips
Commission Member

6 Dissenting reasons of Vice-Chair Michaud

146. In this proceeding, the Commission considers a SASR from FortisAlberta driven by its identification of the need to upgrade the transmission system in the Taber area. Aura has raised a number of concerns that touch upon the AESO's role as a transmission system planner and how it assesses requests for system access service such as this one. In reply argument, Aura reiterated its primary position that "[b]oth the AESO and Fortis have demonstrated that, absent AUC oversight, neither the quantum of the reliability benefit gained nor the costs associated with the System Upgrade and related distribution additions have been considered in determining whether the proposed works are in the public interest."[107] Aura submitted:

> The AESO's and Fortis' filings in support of the Application fail to account for their respective legal obligations to ensure the economic operation of the grid and to provide market participants with reasonable and economic system access. Moreover, the implication of their respective positions in this matter is that there ought to be no limit on the cost of system additions, regardless of how minuscule the associated reliability improvement may be.[108]

147. Having regard to the record of this proceeding, for the reasons that follow, Aura has satisfied me that approval of the NID is not in the public interest and, as such, I would refer the NID back to the AESO.

6.1 FortisAlberta's system access service request

148. As referenced above, the need for the project is a result of FortisAlberta's SASR. In its need for development report, FortisAlberta identifies the underlying rationale for the SASR, which is that "[l]oad growth in the Fincastle area producing a number of concerns related to the adequacy of the existing transmission and distribution facilities to meet the customer needs."[109] FortisAlberta's load studies indicate that under N-1 conditions, unsupplied loads could exist at levels that exceed its planning criteria for electric load restoration.[110] FortisAlberta also determined that while the exceedance of its planning criteria could be met by a distribution-only solution, the distribution capital cost of this solution is significantly higher than the other alternatives it assessed in its need for development report.[111]

149. Aura's concerns with respect to FortisAlberta's identification of the need have been described in detail in this decision. In sum, Aura raised concerns with the adequacy of FortisAlberta's load forecasting and its use of deterministic rather than probabilistic analysis in distribution system planning. Aura submitted that the proposed upgrades at the Fincastle 336S Substation are not a requirement for basic service; rather, they are a reliability enhancement that offers minimal benefit to ratepayers.[112] Aura's concerns with FortisAlberta's identification of the need tie directly into whether the NID is technically deficient or not in the public interest,

107 Exhibit 23393-X0115, Reply Argument of Aura Power, paragraph 2.
108 Exhibit 23393-X0115, Reply Argument of Aura Power, paragraph 2.
109 Exhibit 23393-X0007, Appendix E - DFO Need for Development Report, PDF page 3.
110 Exhibit 23393-X0007, Appendix E - DFO Need for Development Report, PDF page 3.
111 Exhibit 23393-X0007, Appendix E - DFO Need for Development Report, PDF pages 19, 28.
112 Exhibit 23393-X0099, Aura Written Evidence, paragraph 2.

because Aura alleges that the AESO did not adequately investigate FortisAlberta's identification of the need.

150. In considering the underlying need for the project identified by FortisAlberta, I have taken into account FortisAlberta's statutory duties. Similar concerns with respect to distribution planning criteria were raised in the recent Provost decision, in which I also dissented. There, I made the following comments on FortisAlberta's legislated role:[113]

> 290. When FortisAlberta makes a decision to request system access service as part of planning its distribution system, it is guided by its statutory responsibilities. FortisAlberta has a number of duties under Section 105 of the *Electric Utilities Act* which include, among others:
>
> a. to provide electric distribution service that is not unduly discriminatory
>
> b. to make decisions about building, upgrading and improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy having regard to managing losses of electric energy to customers in the service area served by the electric distribution system
>
> c. to operate and maintain the electric distribution system in a safe and reliable manner
>
> 291. FortisAlberta is also obligated under Section 14(2) of the *Transmission Regulation* to assist the AESO in "evaluating the relative merits of transmission and distribution options" and "preparing and updating needs identification documents." This was discussed by the AESO and FortisAlberta witnesses in the hearing, who confirmed that this collaboration between FortisAlberta and the AESO occurred in this case.
>
> 292. What FortisAlberta does not have, however, is a public interest mandate. While FortisAlberta has a number of duties under the legislative scheme which have a view to ensuring safe, reliable and economic delivery of service to members of the public, it remains a regulated utility with its own mandate and responsibilities, both to the public as legislated in the *Electric Utilities Act,* and to its shareholders.

151. My views with respect to FortisAlberta's statutory duties, as described above, have not changed. While FortisAlberta has a duty to make decisions about building, upgrading and improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy, it does not have a public interest mandate. This distinction is important and must be taken into account when evaluating the AESO's responsibilities under the legislative scheme and its approach to assessing the SASR-driven NID at issue in this proceeding.

6.2 The AESO's assessment of the need

152. My dissent in the recent Provost decision covered a number of similar issues as those at play in this proceeding. There, the Commission considered NID and facility applications for enhancements to the transmission system in the Provost area. Like here, the need for the project was driven by a SASR submitted by FortisAlberta, which in turn was driven by its distribution

[113] Decision 23339-D01-2019, paragraphs 290-292.

planning criteria. In the Provost proceeding, the AESO provided evidence on its interpretation of its legislated responsibilities in assessing the different types of NIDs, as follows:[114]

> 295. Under Section 34 of the *Electric Utilities Act,* the AESO is responsible for preparing a NID and filing it with the Commission for approval. Section 34(1) requires the AESO to file a NID when the AESO determines that an expansion or enhancement to the transmission system is or may be required to meet the needs of Alberta and is in the public interest. Subsections 34(1)(a) to (c) identify three different types of NIDs.
>
> a. A NID that describes a constraint or condition affecting the operation or performance of the transmission system and indicates the means by which or the manner in which the constraint or condition could be alleviated.
>
> b. A NID that describes a need for improved efficiency of the transmission system, including the means to reduce losses on the interconnected electric system.
>
> c. A NID that describes a need to respond to a request for system access service.
>
> 296. For the first two types of NID described above, the AESO identifies a need to expand or enhance the transmission system to address constraints or conditions affecting the operation of the system, or to improve the efficiency of the transmission system. These NIDs are the result of an independent assessment by the AESO of transmission system performance.
>
> …
>
> 298. For the third type of NID, a need in response to a market participant's SASR, the AESO approaches the first stage of the NID assessment somewhat differently. This is because the AESO has a duty to provide system access service under the *Electric Utilities Act* to market participants. The phrase "system access service" is defined in Section 1(1)(yy) of the *Electric Utilities Act* as "the service obtained by market participants through a connection to the transmission system for the purpose of exchanging electric energy and ancillary services, and includes (i) access to exchange electric energy and ancillary services, and (ii) access to capacity." In accordance with sections 17(g) and 29 of the *Electric Utilities Act*, the AESO has a duty to provide system access service on the transmission system "in a manner that gives all market participants wishing to exchange electric energy and ancillary services <u>a reasonable opportunity to do so</u>."
>
> …
>
> 301. The AESO's evidence shows that its review of a SASR is different than its review of NIDs to address constraints, conditions or to improve efficiencies on the transmission system. It is clear that the AESO examines the SASR before it in order to ensure that it understands the nature of the need. The evidence also indicates that this process includes posing questions to the market participant and can potentially result in a cancellation of the SASR if a distribution alternative is discovered through that process. There is no dispute that in this proceeding, the AESO assessed the SASR to ensure it had satisfied itself that it understood the nature of the deficiency in FortisAlberta's distribution system.

[114] Decision 23339-D01-2019, paragraphs 295-296, 298, 301-303. [citations omitted]

> 302. However, the AESO's approach to examining the nature of the need identified through a SASR is also clearly constrained by its interpretation of its duty to provide system access service under Section 29 of the *Electric Utilities Act.* The AESO described this duty as follows:
>
>> A. DR. ABDULSALAM: So if I may clarify, it is correct that **the AESO, one of its obligations under the Electric Utilities Act and the transmission regulation, to provide unbiased and open access to the electric transmission system**, and this can get communicated to the AESO through either an application from a distribution facility owner to connect in terms of either a new POD or an expansion or an enhancement, to facilities that will enable the DFO to meet this reliability criteria or additional capacity, or it could be also in the form of a GFO, a generator application, or a load application.
>> So the AESO receiving from a customer a request for service should be taken initially as a valid request for system access that the AESO needs to review and assess and try to meet in the most efficient way. [emphasis added]
>
> 303. It is apparent from the AESO's evidence in this proceeding that it approaches the assessment of SASR-driven NIDs in light of its duty under Sections 17(g) and 29 of the *Electric Utilities Act* to provide system access service. The AESO's interpretation of this duty, as evidenced in its witnesses' testimony, requires it to view the request for system access service as the "need" for the project in itself, and the AESO must rely on the information from the market participant rather than independently assessing whether the project is actually needed based on the driver for the project identified by the market participant.

153. I find that the AESO's evidence on its process for assessing NID applications in response to SASRs is consistent with that given in the Provost proceeding. Here, the AESO described its duty to provide transmission access service and its process in assessing FortisAlberta's SASR in its NID application, as follows:[115]

> The AESO, pursuant to its responsibilities under Section 29 of the Act, must provide system access service on the transmission system in a manner that gives all market participants (in this case the DFO), a reasonable opportunity to exchange electric energy and ancillary services.
>
> The AESO, in consultation with the DFO and the TFO, has determined that the Proposed Transmission Development is the preferred option to meet the DFO's request for system access service. The DFO, in executing its duties as defined under Section 105(1)(b) of the Act, has determined that the Proposed Transmission Development will meet its distribution planning criteria and improve the reliability of the electric distribution services in and around the Municipal District of Taber. The DFO has made the appropriate applications to the AESO to obtain transmission system access service.
>
> Through the AESO Connection Process, the AESO, in consultation with the DFO and the TFO, has determined the characteristics of the Proposed Transmission Development and assessed the impacts that the Proposed Transmission Development and the associated load would have on the transmission system. The AESO has issued directions to the TFO to prepare a transmission facility proposal (Facility Proposal) to meet the DFO's request.

[115] Exhibit 23393-X0002, Fincastle 336S Substation Upgrade NID, PDF page 4, paragraphs 9-11. [citations omitted]

154. The AESO stated in argument that it cannot ignore FortisAlberta's SASR or provide a connection or enhancement to the transmission system that does not reasonably address the nature and scope of the SASR, because "[t]o do so would not provide any opportunity, let alone a reasonable opportunity, to exchange electric energy and ancillary services as required by Section 29 of the *Electric Utilities Act.*"[116] The AESO's evidence and argument in this proceeding show that it assessed the SASR submitted by FortisAlberta to understand FortisAlberta's rationale for submitting the SASR, and to assess the transmission alternatives available to meet the need identified in the SASR.

155. However, it is telling that in the AESO's description of its process reproduced above, it states, "[t]he AESO, in consultation with the DFO and the TFO, has determined that the Proposed Transmission Development is the preferred option to meet the DFO's request for system access service."[117] Notably absent from this description is a statement indicating that the AESO assessed whether the project was needed *at all*, given the nature of the SASR. This is consistent with the AESO's rebuttal evidence describing its role in the SASR review process.[118] I agree with Aura's submission that there is no evidence "that the AESO quantified the reliability benefit, scrutinized Fortis' forecasts, or weighed the benefits of the proposed System Upgrade with the associated costs."[119]

156. In the AESO's view, an assessment of the merits of the SASR as the driver of the need, in itself, is neither required nor permitted by the statutory scheme by virtue of the AESO's duty under Section 29 of the *Electric Utilities Act.* I do not agree with this interpretation.

157. Consistent with my reasoning in Provost,[120] I consider that the AESO's duty to provide system access service in Section 29 of the *Electric Utilities Act* is not unqualified; it does not require the AESO to produce a transmission solution, in every circumstance, at any cost, in response to a SASR filed by an already-grid-connected market participant. Instead, the AESO can and should scrutinize the need identified in a DFO's reliability-driven SASR to determine whether, in fact, a project is needed and in the public interest given its potential impacts. Considering sections 29 and 34(1) of the *Electric Utilities Act* together, the AESO must determine whether the market participant before it *already* has a reasonable opportunity to exchange electric energy, or whether it requires a transmission system expansion or enhancement in order to provide that reasonable opportunity. I consider that the cost-benefit analysis suggested by Aura is precisely what the inclusion of "reasonable" in Section 29 allows the AESO to do.

158. Without such a reasonableness assessment by the AESO, Aura's implication is correct that absent AUC oversight, neither the quantum of the reliability benefit gained nor the costs associated with a project are considered in determining whether any proposed works are in the public interest. This is particularly problematic when one considers that without an intervener participating in a proceeding and satisfying the Commission that the AESO's assessment of the need is technically deficient or approval is not in the public interest, the Commission is bound to consider the AESO's assessment of the need to be correct. While the Commission and the AESO have a public interest mandate, FortisAlberta does not. If the AESO considers FortisAlberta's

116 Exhibit 23393-X0113, AESO Reply Argument, PDF page 7.
117 Exhibit 23393-X0002, Fincastle 336S Substation Upgrade NID, PDF page 4, paragraph 10.
118 Exhibit 23393-X0106, AESO Rebuttal Evidence, PDF pages 4 and 5.
119 Exhibit 23393-X011, Final Argument of Aura Power, paragraph 25.
120 Decision 23339-D01-2019, paragraphs 304-312.

assessment that there is a need for a project, that is, the AESO takes the submission of a SASR as the need in and of itself, it is the entity without a public interest mandate (here, FortisAlberta) that is ultimately making the final decision as to whether the project is needed and in the public interest.

159. In this case, the AESO's "reasonableness enquiry" should have included an assessment of the costs and benefits of the proposed project. In particular, the AESO should have considered whether the benefit produced by the proposed upgrades to the Fincastle 336S Substation, that is, the incremental reliability increase to a system, which on a probabilistic basis, was available 99.99 per cent of the time, is justified given the costs of the project. I have noted above that FortisAlberta does not have a public interest mandate. Moreover, there is a presumption of correctness in favour of the AESO in Section 38(e) of the *Transmission Regulation*. Given these two statutory features, it is critical that the AESO's analysis of these types of DFO-driven SASRs include an analysis of whether the project is needed at all, and in the public interest, having regard for their costs and benefits.

6.3 Conclusions

160. Based on the foregoing, I am satisfied that Aura has met the burden imposed by Section 38(e) of the *Transmission Regulation*, as I find that approving the AESO's NID application would not be in the public interest. I would therefore refer the NID back to the AESO and suggest that the NID application incorporates an analysis of the need for the project that includes a weighing of the expected benefits, such as increased reliability, against its cost and other potential impacts, having regard for the fact that the AESO is not required in all circumstances to respond to a SASR with a proposed transmission solution. Further, I would suggest that a revised NID also contain the AESO's rationale for determining that the proposed project is required to meet the needs of Alberta and is in the public interest, in accordance with Section 34(1) of the *Electric Utilities Act*.

161. Because of my conclusion that approving the NID would not be in the public interest and should be referred back to the AESO, I do not find it necessary to make a determination on AltaLink's facility application.

Dated on February 14, 2019.

Alberta Utilities Commission

(original signed by)

Anne Michaud
Vice-Chair

Appendix A – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Alberta Electric System Operator (AESO) L. Estep
Aura Power Renewables Ltd. (Aura) J. Kennedy

Alberta Utilities Commission Commission panel A. Michaud, Vice-Chair J. Phillips, Commission Member N. Jamieson, Commission Member Commission staff K. Macnab (Commission Counsel) R. Watson (Commission Counsel) K. Elkassem S. Jiang

Appendix B – Abbreviations

Abbreviation	Name in full
AESO	Alberta Electric System Operator
AltaLink	AltaLink Management Ltd.
AUC	Alberta Utilities Commission
DFO	distribution facility owner
DTS	demand transmission service
FortisAlberta	FortisAlberta Inc.
kV	kilovolt
MVA	megavolt ampere
MW	megawatt
NID	needs identification document
POD	point-of-delivery substation
Rule 007	AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*
Rule 012	AUC Rule 012: *Noise Control*
SASR	system access service request
UCA	Utilities Consumer Advocate