

Reference: AESO 2010 ISO Tariff Application, Section 4.5.1, Page 40, paragraph 186

Request:

- (a) Please provide the load forecast for the Alberta-based loads for the Rainbow area, for NW2 and for NW9 that was used in the Northwest Development Plan and any update since that time.
- (b) Please identify the portions of the load forecasts that are derived from DTS contract values and which are derived from forecast values.

Response:

- (a) The load forecast used for the northwest Alberta transmission development was prepared in 2005 and included the following forecast amounts:

Forecast 2005

Area	BC Based Loads	Alberta Based Loads	Total Rainbow Area	Total NW2	Total NW9
Rainbow Area	35	108	143	—	—
NW2	35	130	—	165	—
NW9	32	1,278	—	—	1,310

The amounts were updated in each subsequent load forecast prepared by the AESO. The forecast prepared in 2009 included the following forecast amounts:

Forecast 2009

Area	BC Based Loads	Alberta Based Loads	Total Rainbow Area	Total NW2	Total NW9
Rainbow Area	110	90	200	—	—
NW2	110	111	—	221	—
NW9	107	1,256	—	—	1,363

All forecast amounts represent the sum of market participant metering point values in each respective area, and exclude any losses on the Alberta transmission system.

- (b) None of the Alberta loads were based on contract capacity amounts. The Alberta load forecast is an economic forecast as described in the Overview of the AESO's Future Demand and Energy Outlook included as Appendix C to the *AESO Long-Term Transmission System Plan*, provided as an attachment to information response AUC.AESO-021 (a).

The BC loads were based on a forecast provided to the AESO by BC Hydro.

Reference: AESO 2010 ISO Tariff Application

Request:

Please provide a ten-year history, by month, of:

- (a) Total Alberta Interconnected Electric System (AIES) coincident and non-coincident peak loads;
- (b) NW9 coincident and non-coincident peak loads, excluding Fort Nelson;
- (c) Rainbow area coincident and non-coincident peak loads, excluding Fort Nelson;
- (d) Fort Nelson coincident and non-coincident peak loads.

Response:

The AESO has provided the requested quantities by month from 2005 to 2009. Quantities for years prior to 2005 are not as readily accessible and are not as reliable as quantities from 2005 and later years.

- (a) Please see Attachment BCH.AESO-012 (a).
- (b) Please see Attachment BCH.AESO-012 (b).
- (c) Please see Attachment BCH.AESO-012 (c) Revised.
- (d) Please see Attachment BCH.AESO-012 (d).

Reference: AESO 2010 ISO Tariff Application

Request:

Please provide the AESO's current 5-year forecast, by month, of:

- (a) AIES coincident and non-coincident peak loads;
- (b) NW9 coincident and non-coincident peak loads, excluding Fort Nelson;
- (c) Rainbow area coincident and non-coincident peak loads, excluding Fort Nelson.

Response:

- (a) Please see Attachment BCH.AESO-013 (a).
- (b) Please see Attachment BCH.AESO-013 (b).
- (c) Please see Attachment BCH.AESO-013 (c) Revised.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 46, paragraph 216 & 22

Request:

Please provide a working example calculation that includes calculations for at least a 20-year period of how the capital cost allocation to the proposed FTS rate applicable to BC Hydro would work for the following Development Cases under three separate Scenarios for each Development Case.

The base conditions are:

- BC Hydro requests, and receives, an FTS increase to a total of 75 MW of contracted FTS capacity on January 1, 2013; and
- Financial parameters would be those as are currently applicable for ATCO transmission projects; and
- The NW9 load in Alberta is the forecast underlying the AESO Long Term Transmission System Plan dated 2009 Appendix C Page 182, with identified peak loads of 1258 MW, 1391 MW and 1687 MW in 2013, 2018 and 2028 respectively.

Development Case 1:

The BC Hydro request results in a new capital expansion on the AESO NW system in NW9 of \$295 million (an AESO cost) and \$24 million on the B.C. side (a BCTC cost) (both in 2009 dollars), and provides a transmission capacity increase of 50 MW (from 1310 MW to 1360 MW). The request does not create any new material need for TMR.

Development Case 2:

The BC Hydro request results in a new capital expansion on the AESO NW system in NW9 of \$42 million (an AESO cost) and \$24 million on the B.C. side (a BCTC cost) (both in 2009 dollars), and provides a transmission capacity increase of 50 MW (from 1310 MW to 1360 MW). The request results in a need for 30 average MW of TMR for 1000 hours per year.

Development Case 3:

The BC Hydro request results in a new capital expansion on the AESO NW system in NW2 of \$295 million (an AESO cost) and \$24 million on the B.C. side (a BCTC cost) (both in 2009\$), and that does not provide any change to the 1310 MW of load that can be served in NW9. The request does not create any new material need for TMR.

Scenarios to be tested:

- Scenario 1: BCTC completes a transmission line in 2016, and as a result BC Hydro terminates its FTS contract effective January 1, 2017;
- Scenario 2: The BCTC line enters service in 2020, with the FTS contract terminated effective January 1, 2021; and
- Scenario 3: The FTS contract continues at 75 MW indefinitely.

In particular, for each Scenario under each Development Case:

- calculate the cost impact of this capital investment on the various scenarios under the proposed Rate FTS articles 3(3) and 7(1);
- show the proportion of the 50 MW expansion attributable to BC Hydro and to the AESO (if any), by year; and
- present the net capacity surplus/deficit position for the NW2 region, including BC Hydro load, that would exist if each of the scenarios were to unfold exactly as outlined.
- Show how contract and/or forecast loads in the calculations

Please provide an Excel spreadsheet of calculations and list all assumptions regarding all customer requests in the area.

Response:

Please see Attachments BCH.AESO-018-A Revised through -I Revised for the requested calculations of the capital cost allocations to BC Hydro at Fort Nelson, based on the development cases and scenarios provided in the request. The local system charges to BC Hydro, including applicable termination payments, are summarized in the following table:

Case	Scenario 1	Scenario 2	Scenario 3
1	2010-2013: \$0.5 million/yr 2013-2016: \$17.1 million/yr 2017: \$322.7 million	2010-2013: \$0.5 million/yr 2013-2016: \$2.8 million/yr 2017: \$49.1 million	2010-2013: \$0.5 million/yr 2013-2016: \$17.1 million/yr 2017: \$322.7 million
2	2010-2013: \$0.5 million/yr 2013-2020: \$17.1 million/yr 2021: \$284.2 million	2010-2013: \$0.5 million/yr 2013-2020: \$2.8 million/yr 2021: \$42.8 million	2010-2013: \$0.5 million/yr 2013-2020: \$17.1 million/yr 2021: \$284.2 million
3	2010-2013: \$0.5 million/yr 2013-2034: \$17.1 million/yr 2035-2063: \$16.7 million/yr	2010-2013: \$0.5 million/yr 2013-2034: \$2.8 million/yr 2035-2063: ≥\$2.4 million/yr	2010-2013: \$0.5 million/yr 2013-2034: \$17.1 million/yr 2035-2063: \$16.7 million/yr

As the AESO's most recent operational studies indicate it cannot serve more than 40 MW of load at Fort Nelson, the AESO assumes that the capital expansions in each of the development cases would allow it to serve the 75 MW proposed to be contracted in 2013.

As the analysis relates to the cost impact under subsections 3(3) and 7(1) of proposed Rate FTS, there is no effect related to changing TMR requirements. TMR charges to BC Hydro at Fort Nelson would be determined based on actual hourly TMR generation and cannot be estimated in advance based on the information provided.