aeso ALBERTA ELECTRIC SYSTEM OPERATOR

Supplementary 2018 Forecast Information

1. Disclaimer

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Refer to slides 5-11

2. Pool Price

a) 2017 Pool Price

The 2017 projected average pool price is $24 per MWh compared to the 2017 forecast pool price of $32 per MWh (as provided in the 2017 Budget Review Process (BRP)). The 2017 projection incorporates actual pool prices and forecast information from the EDC Associates' "Quarterly Forecast Update: First Quarter 2017".

The 2017 projected average pool price is lower than the previous forecast mainly due to changes in offer behavior.

b) 2018 Pool Price Forecast

Consistent with the 2017 BRP, the AESO has chosen to use the EDC Associates' hourly pool price forecast for 2018. While the AESO has prepared an internal hourly pool price forecast in recent years, competing priorities for the staff resources contributed to the decision to continue to use EDC for the 2018 BRP. The hourly pool price forecast is used as an input to calculate the ancillary services and transmission line losses costs.

There are numerous variables and assumptions used in the hourly pool price forecast and it is understood that the following assumptions have been considered by EDC:

- expectation that more generating assets will be offered at close to marginal costs for 2017 with a return of strategic offer behavior in 2018;
- no impact for accelerated coal unit retirements in 2017 and 2018; and
- pricing impacts associated with the new carbon performance standard in Alberta will increase in January 2018.

It should be noted that the EDC 2018 forecast does not incorporate the April 2017 announcement from TransAlta regarding the retirement of Sundance 1 or mothballing Sundance 2 for up to 2 years (both effective Jan 2018) which may impact the 2018 pool prices. The transmission tariff rate riders ensure a timely correction to tariff rates to incorporate variances in cost forecasts, including from pool price variances.

The 2018 average pool price is forecast to be $43 per MWh compared to the 2017 projected average pool price of $24, an increase of 81 per cent. The higher pool prices anticipated for 2018 are due to:

- anticipated return of strategic offer behavior;
- implementation of a new carbon performance standard; and
- higher demand.

Refer to slides 12-15

3. Load Forecast

a) 2017 Load

2017 Alberta Internal Load (AIL) is projected to be higher than 2016 actuals due to:

- economic and population growth
- oilsands production growth
- normal weather assumptions compared to milder temperatures in 2016

There was observable load growth in Q1 2017. There is no impact of the 2016 fires in Northern Alberta load growth (i.e. no lost load).

2017 AIL is projected to be higher than 2017 BRP due to:

- higher economic growth
- colder winter temperatures

b) 2018 Load Forecast

Projected load growth in 2017 compared to 2016 is 3.7 per cent due to anticipated economic expansion in Alberta. The 2018 AIL is anticipated to increase a further 2.5 per cent over 2017 from continued economic expansion. Overall, the 2018 AIL forecast results in an annual average growth rate of three per cent from the 2016 actual load.

The 2018 BRP load forecast utilizes economic inputs from the Conference Board of Canada's November 2016 Canada economic outlook, including Gross Domestic Product (GDP), employment, and population variables for Alberta. The 2018 BRP load forecast also includes considerations for seasonality, days of the week, hour of the day, holidays, and normal weather (median temperatures over the last 11 years).

Refer to slides 16-17

4. Wires

a) Description of Service

Wires costs represent the amounts paid primarily to transmission facility owners (TFOs) in accordance with their Alberta Utilities Commission (AUC)-approved tariffs and are not controllable costs of the AESO nor are these approved by the AESO Board. Wires costs also include long-term contracts related to Invitation to Bid on Credit (IBOC) and Location Based Credit Standing Offer (LBC SO) programs, since these programs were initiated as incentives for generation to locate closer to major load centres and provide a non-wires solution to transmission wires issues in Alberta. These forecasts are approved by the AESO Board.

b) Update of 2017 BRP

Wires costs in the 2017 projection are $1,697.1 million, which is $32.2 million or two per cent lower than the 2017 BRP of $1,729.3 million based on the amounts paid primarily to the TFOs in accordance with their AUC-approved tariffs.

The 2017 projection is based on TFO tariffs approved or applied-for as of April 2017 with a majority of the projection reflecting: i) a negotiated settlement for a 2017 tariff; ii) a compliance filing for a 2017 tariff; or iii) AUC approvals for 2017 tariffs.

c) 2018 Forecast

The 2018 forecast for wires costs is $1,723.0 million, which is $25.9 million or two per cent higher than the 2017 projection of $1,697.1 million. The 2018 forecast is based on TFO tariffs ($1,717.6 million) and the AESO's forecast for IBOC and LBC SO costs ($5.4 million).

The 2018 forecast is based on TFO tariffs approved or applied-for as of April 2017 with a majority of the forecast reflecting: i) a filing for a 2018 tariff; ii) a compliance filing for a 2017 tariff; or iii) AUC approvals for 2017 tariffs.

Refer to slides 18-20

5. Ancillary Services

Ancillary services are procured by the AESO to ensure reliability of the transmission system and include operating reserves and services with generation capacity and load reduction capabilities. Ancillary services are procured through various methods including a daily competitive exchange for operating reserves and competitive processes that result in contracts for other types of ancillary services.

5.1. OPERATING RESERVES

a) Description of Service

Operating reserves are generating capacity or load that is held in reserve and made available to the System Controller to manage the transmission system supply-demand balance in real time. The procurement of operating reserve volumes is directly correlated to load and generation. Operating reserves are procured through an online, day-ahead exchange. In exchange for this payment, the AESO obtains the right to utilize the provider's energy and/or capacity as reserves. Over-the-counter contracts are used only as a back up to procure operating reserves in the absence of the availability of the online exchange. All providers who sell volumes over-the-counter are paid their offer price.

Categories of Operating Reserves

1) **Active operating reserves:**
   - required to automatically balance small changes in supply and demand
   - required to maintain system reliability during unplanned events such as the loss of a generator, loss of a transmission line, or a sudden increase in demand
   - Alberta Reliability Standards (ARS) define the minimum levels that must be procured
   - costs are the product of volumes procured multiplied by operating reserve price, which is indexed to the hourly pool price
   - represents approximately 80 per cent of total operating reserves costs
   - costs are impacted by pool price fluctuations, supply of offered reserves and market participant offer behavior

2) **Standby operating reserves:**
    - provide additional reserves when the active operating reserves are insufficient to ensure system reliability
    - pricing includes two components: i) an option premium, paid for the capability to activate the standby reserves; and ii) an activation price, paid only if the standby reserves are activated
    - represents approximately 20 per cent of total operating reserves costs

Operating Reserve Products (in both the active and standby markets)

1) **Regulating reserves** – The generation capacity, energy and maneuverability responsive to the AESO's automatic generation control (AGC) system that is required to automatically balance supply and demand on a minute-to-minute basis in real time.

2) **Spinning reserves** – Unloaded generation that is synchronized to the transmission system, automatically responsive to frequency deviation and ready to provide additional energy in response to an AESO System Controller directive. Spinning reserve suppliers must be able to ramp up their generator within 10 minutes of receiving a System Controller directive.

3) **Supplemental reserves** – While similar to spinning reserves, supplemental reserves are not required to respond to frequency deviations. They include unloaded generation, off-line generation or system load that is ready to serve additional energy (generator) or reduce energy (load) within 10 minutes of receiving a System Controller directive.

b) Update of 2017 BRP

The Operating reserves projection for 2017 is based on:

- **actual hourly volumes of operating reserves and hourly pool prices**: January 2017
- **forecast hourly volume of operating reserves**: based on ARS requirements using simulated generation and load data;
- **forecast hourly pool prices**: obtained from the EDC Associates' Q1 2017 Update Report for the period from March 2017 to December 2017; and
- **estimated operating reserve prices**: average prices over the previous 24 months of historical data.

Operating reserve costs in the 2017 projection are $60.8 million, which is $27.4 million or 31 per cent lower than the 2017 BRP of $88.2 million. The cost of operating reserves is impacted by actual volumes, hourly pool prices and operating reserve prices.

The 2017 projected operating reserves volumes is 7.4 terawatt hours, which is 0.1 terawatt hours or one per cent higher than the 2017 BRP of 7.3 terawatt hours. The volume variance is mainly attributable to an anticipated increase in load.

The cost variance is mainly attributable to a lower 2017 projected average pool price of $24 per MWh compared to $32 per MWh used in the 2017 forecast.

c) 2018 Forecast

The 2018 forecast for operating reserves costs is $96.8 million, which is $36.0 million or 59 per cent higher than 2017 projected costs of $60.8 million.

The 2018 operating reserves volume forecast is 7.5 terawatt hours, which is 0.1 terawatt hours or one per cent higher than the 2017 projection of 7.4 terawatt hours associated with a forecast increase in load.

The cost variance is mainly attributable to a higher 2018 forecasted average pool price of $43 per MWh, which is 81 per cent higher than the 2017 projection of $24 per MWh.

5.2. OTHER ANCILLARY SERVICES

a) Description of Service

The AESO procures other ancillary services for the secure and reliable operation of the Alberta Interconnected Electric System (AIES). These services are procured through a competitive procurement process where possible, or in such instances where such procurements may not be feasible, through bilateral negotiations.

Load shed service for imports (LSSi) is interruptible load that can be armed to trip, either automatically or manually, on the loss of the Alberta-British Columbia intertie to allow for increased import available transfer capability (ATC).

Black start services are provided by generators that are able to restart their generation facility with no outside source of power. In the event of a system-wide black-out, black start services are used to re-energize the transmission system and provide start-up power to generators who cannot self-start. Black start providers are required in specific areas of the Alberta Interconnected Electrical System (AIES) to ensure the entire system has adequate start-up power.

Transmission must-run (TMR) occurs when generation is required to mitigate the overloading of transmission lines associated with line outages, system conditions in real time or the loss of generation in an area. In circumstances when this service is required for an unforeseeable event and there is no contracted TMR, non-contracted generators may be dispatched to provide this service (referred to as conscripted TMR). In the event of foreseeable TMR, the AESO may enter into a contract with a generator to provide TMR services.

The Poplar Hill generator provides voltage support (VArs) in addition to power (MW), to support the transmission system reliability in the province.

Reliability services are provided through an agreement with Powerex Corp. for grid restoration balancing support in the event of an Alberta blackout and emergency energy in the event of supply shortfall. The agreement came into effect on April 1, 2015.

Transmission constraint rebalancing costs are incurred when the transmission system is unable to deliver electricity from a generator to a given electricity consuming area without contravening reliability requirements. When this occurs, a market participant downstream of a constraint may be dispatched for purposes of transmission constraint rebalancing under the ISO Rules and would receive a transmission constraint rebalancing payment for energy provided for that purpose. Transmission constraint rebalancing came into effect on November 26, 2015.

b) 2018 Forecast

The 2018 forecast for other ancillary services costs is $32.7 million, which is $1.4 million or four per cent higher than the 2017 projection of $31.3 million.

Other Ancillary Services Costs ($ million) ~ by production year

	2018 Forecast	2017 Projected	2017 BRP	2016 Actual	2015 Actual
Load Shed Service for Imports	17.3	18.1	18.1	18.2	17.4
Contracted Transmission Must-run	3.3	3.3	2.8	n/a	n/a
Conscripted Transmission Must-run	2.0	2.0	2.0	1.3	9.7
Reliability Services	2.9	2.9	2.9	2.9	2.1
Poplar Hill	2.8	2.8	2.8	2.8	2.6
Black Start	4.3	2.1	2.1	2.1	2.1
Transmission Constraint Rebalancing	0.1	0.1	0.1	0.0	n/a
Other Ancillary Service Costs	32.7	31.3	30.8	27.3	33.9

Differences are due to rounding

Updates to 2017 costs from the 2017 BRP due to:

- **Contracted Transmission Must-run** – new contract for TMR services to address reliability requirements

The 2018 forecast methodology:

- **Load Shed Service for Imports** (LSSi) – considers the overall operations of the AIES in 2018 (which impacts arming and tripping requirements) and an anticipated lower LSSi volume availability
- **Contracted Transmission Must-run** – new contract signed in 2017
- **Conscripted Transmission Must-run** – based on the 2017 projected cost as operational conditions in 2018 are anticipated to be similar to those in 2017
- **Reliability Services** – based on an existing contract; no new contracts for services in 2018
- **Poplar Hill** –operational conditions in 2018 are anticipated to be similar to those experienced in 2017
- **Black Start** – new contract planned for 2018
- **Transmission Constraint Rebalancing** – based on the operational conditions in 2018 which are anticipated to be similar to those experienced in 2016 and projected for 2017

Refer to slides 21-23

6. Line Losses

a) Description of Service

Transmission line losses represent the volume of energy that is lost as a result of electrical resistance on the transmission lines. Volumes associated with line losses are determined through the energy market settlement process as the difference between generation and import volumes, less consumption and export volumes. The hourly volumes of line losses vary based on load and export levels, generation (baseload, peaking units and import) available to serve load, weather conditions, and changes in the transmission topology. System maintenance schedules, unexpected failures, dispatch decisions on the AIES, and short-term system measures (such as demand response) may also affect the volume of losses.

The annual volume forecast for transmission line losses is based on the hourly forecast losses volumes, which are based on:

- statistical models that use forecast load as an input; and
- normal weather.

The annual forecast for transmission line losses costs is the aggregate of the hourly forecast losses volumes multiplied by the hourly forecast pool prices. As such, the transmission line losses costs are highly correlated with the pool price forecast.

b) Update of 2017 BRP

Transmission line losses costs in the 2017 projection are $53.5million, which is $20.6 million or 28 per cent lower than the 2017 BRP of $74.1 million.

The 2017 projected transmission line losses volumes is 2,267 gigawatt hours, which is 24 gigawatt hours or one per cent lower than the 2017 BRP of 2,291 gigawatt hours. The volume of losses has remained consistent despite load growth due in part to transmission system enhancements.

The cost variance is mainly attributable to a lower 2017 projected average pool price of $24 per MWh compared to $32 per MWh used in the 2017 forecast.

c) 2018 Forecast

The 2018 forecast for transmission line losses is $96.7 million, which is $43.2 million or 81 per cent higher than the 2017 projected cost of $53.5 million.

The 2018 transmission line losses volume forecast is 2,225 gigawatt hours, which is 42 gigawatt hours or two per cent lower than the 2017 projection of 2,267 gigawatt hours. The volume of losses has remained consistent despite load growth due in part to transmission system enhancements.