Supplementary 2019 Forecast Information

1. Disclaimer

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Refer to slides 6-9

2. Pool Price

a) 2018 Pool Price

The 2018 projected average pool price is $50 per MWh compared to the 2018 forecast pool price of $43 per MWh (as provided in the 2018 Budget Review Process (BRP)). The 2018 projection incorporates actual pool prices (from January 2018-August 2018) and forecast information from the EDC Associates' "Quarterly Forecast Update – Third Quarter 2018".

The 2018 projected average pool price is higher than the previous forecast mainly due to changes in carbon pricing, retirement impacts, higher than expected demand, and changes to offer behavior.

b) 2019 Pool Price Forecast

Consistent with the 2017-2018 BRP, the AESO has chosen to use the EDC Associates' hourly pool price forecast for 2019. While the AESO has prepared an internal hourly pool price forecast in previous years, competing priorities for the staff resources contributed to the decision to continue to use EDC for the 2019 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:

- recent market fundamentals
- the impact of the Carbon Competitiveness Incentive Regulation (CCIR) and
- pricing impacts associated with retirements/mothballs, and Renewable Electricity Program (REP) round one additions

The 2019 average pool price is forecast to be $58 per MWh compared to the 2018 projected average pool price of $50, an increase of 16 per cent. The higher pool prices anticipated for 2019 are in part due to:

- continued strategic offer behavior
- higher demand

Refer to slides 11-13

3. Load Forecast

a) 2018 Load

2018 Alberta Internal Load (AIL) is projected to be higher than 2017 actuals due to:

- economic and population growth
- oilsands production growth
- new sources of load being added to the system
    - year-to-date load growth is 3.6% over 2017

2018 AIL is projected to be higher than 2018 BRP due to:

- the addition of new cryptocurrency mining load and faster than expected ramp-up of oilsands projects

b) 2019 Load Forecast

Projected load growth in 2018 compared to 2017 is three per cent higher due to economic expansion, increased oil production, and new loads. 2019 AIL is anticipated to increase a further one per cent over 2018 from continued economic expansion and population growth.

The 2019 BRP load forecast utilizes economic inputs from the Conference Board of Canada's Spring 2018 Outlook, including real gross domestic product (GDP), employment, and population variables for Alberta. The 2019 BRP load forecast also includes considerations for oil production, seasonality, days of the week, hour of the day, holidays, and normal weather (median temperatures over the last 30+ years).

Refer to slide 15

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 2018 Wires

Wires costs in the 2018 projection are $1,712.7 million, which is $10.3 million or one per cent lower than the 2018 BRP forecast of $1,723.0 million based on the amounts paid primarily to the TFOs in accordance with their AUC-approved tariffs.

The 2018 projection is based on TFO tariffs approved or applied-for as of August 2018 with a majority of the projection reflecting: i) filed 2018 tariffs; ii) AUC approved 2018 interim tariffs; or iii) AUC approvals for 2017 and 2018 tariffs.

c) 2019 Forecast

The 2019 forecast for wires costs is $1,767.6 million, which is $55.0 million or three per cent higher than the 2018 projection of $1,712.7 million. The 2019 forecast is based on TFO tariffs ($1,763.0 million) and the AESO's forecast for IBOC and LBC SO costs ($4.6 million).

The 2019 forecast is based on TFO tariffs approved or applied-for as of October 2018 with a majority of the forecast reflecting: i) filed 2018 and 2019 tariffs; or ii) AUC approvals for 2017 tariffs and 2018 interim approved tariffs.

Refer to slides 17-18

5. Ancillary Services

Ancillary services are procured by the AESO to ensure reliability of the 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

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 2018 BRP

The Operating reserves projection for 2018 is based on:

- **actual hourly volumes of operating reserves and hourly pool prices/OR prices**: January-August 2018
- **forecast hourly volume of operating reserves**: based on Alberta Reliability Standards requirements using forecast generation, load, and import data;
- **forecast hourly pool prices**: obtained from the EDC Associates' Quarterly Forecast Update – Third Quarter 2018 for the period from August 2018 to December 2018; and
- **estimated operating reserve prices**: average prices over the previous 24 months of historical data.

Operating reserve costs in the 2018 projection are $250.4 million, which is $103.8 million or 71 per cent higher than the 2018 BRP forecast of $146.6 million. The cost of operating reserves is impacted by actual volumes, hourly pool prices, and operating reserve prices.

The 2018 projected operating reserves volumes is 8.1 terawatt hours, which is 0.6 terawatt hours or eight per cent higher than the 2018 BRP forecast of 7.5 terawatt hours. The volume variance is mainly attributable to an increase in load and imports.

The cost variance is mainly attributable to a higher 2018 projected average pool price of $50 per MWh compared to $43 per MWh used in the 2018 forecast, and higher than expected volumes. In addition, pool price volatility in 2018 has contributed to a large increase in the number of hours of prices exceeding $100/MWh compared to the previous forecast. The 2018 BRP forecast had 88 hours of prices above $100/MWh, and the new projection has 359 hours above $100/MWh.

For additional context, the projected 2018 OR costs are in-line with previous years with similar pool prices (see slide 17 of the AESO 2019 Preliminary Business Plan and Budget Information presentation for historic comparisons).

c) 2019 Forecast

The 2019 forecast for operating reserves costs is $270.6 million, which is $20.3 million or eight per cent higher than 2018 projected costs of $250.3 million.

The 2019 operating reserves volume forecast is 7.9 terawatt hours, which is 0.2 terawatt hours or three per cent lower than the 2018 projection of 8.1 terawatt hours associated with a lower forecast of import volumes than projected 2018.

The cost variance is mainly attributable to a higher 2019 forecasted average pool price of $58 per MWh, which is 16 per cent higher than the 2018 projection of $50 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 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) 2019 Forecast

The 2019 forecast for other ancillary services costs is $43.2 million, which is $0.7 million or two per cent lower than the 2018 projection of $43.9 million.

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

	2019 Forecast	2018 Projected	2018 BRP	2017 Actual	2016 Actual
Load Shed Service for Imports	32.8	32.8	17.3	22.9	18.2
Contracted Transmission Must-run	3.2	3.0	3.3	3.0	n/a
Conscripted Transmission Must-run	0.2	0.2	2.0	0.5	0.7
Reliability Services	2.9	2.9	2.9	2.9	2.9
Poplar Hill	1.7	2.7	2.8	2.8	2.8
Black Start	2.3	2.2	4.3	2.1	2.1
Transmission Constraint Rebalancing	0.1	0.1	0.1	0.0	0.0
Other Ancillary Service Costs	43.2	43.9	32.6	34.3	26.8

Differences are due to rounding

Updates to 2018 costs from the 2018 BRP due to:

- **Load Shed Service for Imports (LSSi)** – Significant unbudgeted LSSi utilization in 2018 due to low and negative Mid-C pricing and higher pricing in Alberta. Low Mid-C pricing is being driven by high hydro-flows in the Pacific Northwest while higher Alberta pricing is being driven higher by increased carbon costs (*Carbon Competitiveness Incentive Regulation*). This resulted in higher import volumes requiring higher LSSi utilization.

- **Conscripted Transmission Must-run** are real-time events and there have been a reduced number of events than was forecast for the 2018 BRP.

- **Black Start** – 2018 BRP forecast had contemplated additional Black Start agreements. No additional agreements have been formalized at this time.

The 2019 forecast methodology:

- **Load Shed Service for Imports** (LSSi) – considers the overall operations of the AIES in 2019 (which impacts arming and tripping requirements) and an anticipated LSSi volume availability of 75%

- **Contracted Transmission Must-run** – includes units currently under contract. The TMR agreement is forecast at 100% availability for the purpose of the 2019 Forecast.

- **Conscripted Transmission Must-run** – based on the 2018 projected cost as operational conditions in 2019 are anticipated to be similar to those in 2018

- **Reliability Services** – based on an existing contract; no new contracts for services in 2019.

- **Poplar Hill** –operational conditions in 2019 are anticipated to be similar to those experienced in 2018. The Monthly Fixed Capital Payment will reduce by approximately 50% at the end of September, 2018, which will reduce the overall payment by approximately $1M per year for the remainder of the contract.

- **Black Start** – no additional black start services are planned for 2019. The 2019 Forecast includes the fixed payments for the agreements for existing units under contract.
- **Transmission Constraint Rebalancing** – based on the operational conditions in 2019 which are anticipated to be similar to those experienced in 2017 and projected for 2018

Refer to slides 20-21

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 statistical models that use variables including forecast load, hourly, daily, and seasonal effects to forecast hourly losses volumes.

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 2018 BRP

Transmission line losses costs in the 2018 projection are $105.2 million, which is $8.5 million or nine per cent higher than the 2018 BRP of $96.7 million.

The 2018 projected transmission line losses volumes is 2,012 gigawatt hours, which is 213 gigawatt hours or ten per cent lower than the 2018 BRP of 2,225 gigawatt hours. The volume of losses has decreased this year despite considerable load growth. This impact is likely attributed to significant changes in generation dispatches from high imports and gas-fired generation in conjunction with lower coal-fired generation

In addition, the cost variance is mainly impacted by a higher 2018 projected average pool price of $50 per MWh compared to $43 per MWh used in the 2018 forecast.

c) 2019 Forecast

The 2019 forecast for transmission line losses is $126.1 million, which is $20.9 million or 20 per cent higher than the 2018 projected cost of $105.2 million. This is mostly attributable to the forecast increase in the 2019 pool price ($58 per MWh compared to $50 per MWh) .

The 2019 transmission line losses volume forecast is 2,110 gigawatt hours, which is 98 gigawatt hours or five per cent higher than the 2018 projection of 2,012 gigawatt hours.