AESO Quarterly Stakeholder Report

Q3 2017

- Initiative Updates
- Financial Highlights

Quarterly Stakeholder Report – Third Quarter (July to September) 2017

The purpose of this section of the quarterly report is to provide stakeholders with an update on the Alberta Electric System Operator's (AESO) progress on the initiatives outlined in its 2017-2018 Business Plan and Budget Proposal (Business Plan). The reader of this report should reference the Business Plan published on the AESO's website for additional information to fully understand the various progress updates provided.

I. Reporting on Business Plan Initiatives by Activity Group

Electric System Operations			
Business Initiative	**Current Status**	**Next Milestone**	**Target**
Alberta Reliability Standards (ARS) Critical Infrastructure Protection (CIP)	AESO became CIP compliant as of October 1, 2017	None	Successful Western Electricity Coordinating Council (WECC) CIP audit of AESO compliance with standards in Q1 2018
	ARS CIP Standard CIP-014-AB-02 (Physical Security) drafting complete	CIP-PLAN for CIP-014 implementation to be drafted. Stakeholder consultation for proposed ARS CIP-014 and CIP-PLAN expected in 2018	CIP-014 standard expected to be filed with the Alberta Utilities Commission (AUC) in 2018
Alberta Interconnected Electrical System (AIES) - enhancements (reliability and integration)	Energy Management System (EMS) Upgrade Project (implementation phase) - Deployment into production completed	None	EMS Upgrade Project to be completed by Q4 2017
	Wide Area Network (WAN) Implementation – network testing and migration activities underway	Completion of migration activities	WAN expected to be fully operational by Q4 2017
	SCC Expansion Project (implementation phase): Request For Proposal (RFP) for construction contractor process underway	Award construction contract to RFP winner	Initiate construction in Q1 2018

Electric System Development			
Business Initiative	Current Status	Next Milestone	Target
Advance system and regional transmission projects identified in the LTP	AUC decision received for the Calgary Downtown Reinforcement Project Need Identification Document (NID) June 2016	Calgary Downtown Reinforecment Project FA expected to be filed by Q4 2017 Support TFO facility application (FA) development	Ongoing support of TFOs with FAs,certifications and FA hearings
	AESO filed NID for the Provost to Edgerton and Nilrem to Vermillion (PENV) project December 16, 2016	PENV written hearing ongoing and scheduled to conclude in Q4 2017 AUC decision of PENV NID filing expected in Q1 2018	Ongoing
	AESO advancing North West (NW) transmission development plans toward the NID filing stage	AESO expects to file with the AUC the Rycroft Transmission Reinforcement NID, a component of the NW transmission plan by Q4 2017	Ongoing
Intertie Restoration	AESO has developed an intertie restoration schedule/strategy and will be providing updates to industry starting in Q4 2017	AESO will complete design and development of intertie requirements and initiate consultation by Q1 2018	Ongoing
Competitive Process (for transmission)	A debt funding competition for the Fort McMurray West 500 kV Transmission Project (West Project) was conducted in June/July 2017. The West Project has successfully reached financial close and is currently under construction	None	Target in-service date for the West Project is 2019
	Based on the current economic environment and sustained low oil prices, the AESO is deferring the launch date of the Fort McMurray East 500kV Transmission Project (East Project)	None	Reassessment of launch date of the East Project is ongoing

Electric System Development - continued			
Business Initiative	**Current Status**	**Next Milestone**	**Target**
Tariff rate information and updates	In Q3 2017, the AESO filed the Rider C, *Deferral Account Adjustment Rider*, amendment application for changes to Rider C and the deferral account reconciliation methodology on an interim refundable basis. This application was filed as part of the 2018 ISO tariff application	Ongoing	The application included a request for approval to be effective as early as practical. The AESO has communicated to the AUC that approval by November 30, 2017 would allow implementation of the interim changes by January 1, 2018
	In Q3 2017, the AESO filed the 2018 ISO tariff application (formerly referred to as the 2017 ISO Tariff Application) In Q3 2017, the AESO filed its Transmission Rate Projection (TRP) model with the 2018 ISO Tariff Application	AUC Decision of 2018 ISO tariff expected by Q4 2018 Ongoing	Ongoing An updated TRP, to incorporate the next Long Term Plan (LTP) results, will be published and filed with the AUC after the LTP is published in 2018

Customer Access Services			
Business Initiative	**Current Status**	**Next Milestone**	**Target**
Advance customer connection projects within the connection queue[1]	AESO facilitating the advancement of approved System Access Service Requests for customer connection projects	Support customer projects facilitating the in-service date (ISD)	Ongoing support of customer FAs, certifications and FA hearings
	34 customer energizations (including Connection, Contract and Behind-the-Fence projects) completed as of September 30, 2017	Ongoing	Ongoing
	6 customer connection Abbreviated Need Identification Documents (ANID)s filed with the AUC (none of which were Market Participant Choice projects) and no Abbreviated Needs Approval Process (ANAP) customer connection projects were approved as of September 30, 2017	NID development and filings as per schedule	Ongoing

[1] See www.aeso.ca > Grid > Connecting to the grid > Connection project list - for a complete list of projects in the connection queue and the current status.

Market Development			
Business Initiative	**Current Status**	**Next Milestone**	**Target**
Market system replacement and re-engineering (MSR) project	Advance medium-term reliability and security measures identified for 2017	Ongoing	Successfully complete medium-term sustainment measures by year end 2017
Climate change program	AESO launched the first REP competition (REP Round 1) in Q1 2017 AESO continues to work with the Government of Alberta (GoA) on Renewable Electricity Program (REP)	AESO expects to select the successful proponent(s) in REP Round 1 and execute Renewable Electricity Support Agreement(s) by the end of 2017	First REP project(s) are expected to be in service by Q4 2019
Capacity Market	AESO consulting with stakeholders to develop Capacity Market Design	Development of next iteration of Straw Alberta Market (SAM) by December 2017	Design and Term Sheets for Capacity Market complete by Q2 2018

II. Financial Update – As of September 30, 2017

Transmission Operating Costs ($ million) – by accounting month

	YTD 2017 Actual	YTD 2017 Forecast	YTD 2016 Actual
Wires costs	1,262.3	1,297.0	1,163.4
Operating reserves	61.4	67.2	47.4
Transmission line losses	38.6	55.3	31.3
Other ancillary service costs	26.7	23.0	20.8
Transmission operating costs	**1,389.0**	**1,442.5**	**1,262.9**

Numbers may not add due to rounding

Wires costs – 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.

The 2017 forecast was based on TFO tariffs approved or applied-for as of October 20, 2016 with the forecast reflecting: i) compliance filings for 2016 tariffs; ii) compliance filings for 2017 tariffs; or iii) AUC approvals for 2017 tariffs. Year-to-date 2017 wires costs reflect current AUC decisions.

Operating reserves – 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. Operating reserves are procured through an online, day-ahead exchange, where offer prices are indexed to the pool price. While the prices of operating reserves procured through the online exchange are indexed to the pool price, changes to the average pool price do not result in proportional changes to the operating reserve costs; the pool price for each hour has a significant impact on the operating reserve costs for that hour.

Year-to-date September 2017 operating reserve costs are lower than forecast mainly due to active operating reserves where volumes are three per cent higher than forecast and costs are eight per cent lower than forecast. The costs are impacted by the lower than forecast pool price and operating reserve prices.

The active operating reserve costs from May to July 2017 were impacted by higher imports on the AB-BC intertie which required higher volumes of operating reserves. During this period, active operating reserve costs were $9.6 million or 76 percent higher than forecast while the volumes were eight per cent higher than forecast.

The year-to-date September 2017 average pool price is $22 per megawatt hour (MWh) compared to a forecast of $33 per MWh and 2016 actual year-to-date September average pool price of $17 per MWh.

Transmission line losses – 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 imports) available to serve load, weather conditions, and changes in the transmission topology. System maintenance schedules, unexpected failures, dispatch decisions on the Alberta interconnected electric system (AIES), and short-term system measures (such as demand response) may also affect the volume of losses. The value of line losses is calculated based on the hourly pool price.

Year-to-date 2017 transmission line loss costs are lower than forecast due to the lower average pool price offset by volumes three per cent higher than forecast.

Other ancillary services costs – The AESO procures other ancillary services for the secure and reliable operation of the AIES. These services are procured through a competitive procurement process where possible, or in instances where such procurement processes may not be feasible, through bilateral negotiations.

Other Ancillary Services Costs ($ million) – by accounting month

	YTD 2017 Actual	YTD 2017 Forecast	YTD 2016 Actual
Load shed service for imports	18.3	13.5	13.3
Transmission must-run			
Contracted	2.3	2.1	-
Conscripted	0.3	1.5	1.6
Reliability services	2.1	2.1	2.1
Poplar Hill	2.1	2.1	2.1
Black start	1.6	1.6	1.6
Transmission constraint rebalancing	0.0	0.1	-
Total Other ancillary services	**26.7**	**23.0**	**20.8**

Numbers may not add due to rounding

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). LSSi costs are impacted by volume availability, contract prices and AIES system requirements for arming and tripping requirements. Actual costs in 2017 are higher than forecast due to a higher number of arming events required for operational purposes and higher volume availability.

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).

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

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 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 Independent System Operator (ISO) Rules and would receive a transmission constraint rebalancing payment for energy provided for that purpose.

Other Industry Costs ($ million)

	YTD 2017 Actual	YTD 2017 Forecast	YTD 2016 Actual
Alberta Utilities Commission (AUC) fee – Transmission	8.6	9.5	9.0
AUC fee – Energy Market	4.4	5.2	4.9
WECC/NWPP costs	1.6	1.7	1.8
Regulatory process costs	1.0	1.1	0.9
Total other industry costs	**15.6**	**17.4**	**16.6**

Numbers may not add due to rounding

Other industry costs represent fees or costs paid based on regulatory requirements or membership fees for industry organizations, which are not under the direct control of the AESO. These costs relate to the annual administration fee for the AUC, the AESO's share of Western Electricity Coordinating Council (WECC) and Northwest Power Pool (NWPP) membership fees and regulatory process costs. Regulatory process costs are associated with the AESO's involvement in an AUC proceeding to hear objections and complaints to ISO Rules or a regulatory application and costs incurred to respond to specific agency-related directions or recommendations that are beyond the routine operations of the AESO; this does not include application preparation costs.

General and Administrative Costs ($ million)

	YTD 2017 Actual	YTD 2017 Budget	YTD 2016 Actual
Staff costs	48.9	48.7	48.4
Contract services and consultants	9.7	8.1	6.4
Facilities	5.2	5.3	5.4
Administration	2.9	2.8	3.2
Computer services and maintenance	7.7	7.9	7.1
Telecommunications	1.0	1.0	1.1
General and administrative costs	**75.4**	**73.9**	**71.6**

Numbers may not add due to rounding

Interest and Amortization ($ million)

	YTD 2017 Actual	YTD 2017 Budget	YTD 2016 Actual
Amortization of intangible assets and depreciation of property, plant and equipment	15.0	14.1	17.2
Interest	0.6	0.7	1.2

Capital Expenditure Update – As of September 30, 2017

Capital Program ($ million)	Total Project Approved	Prior Year(s) Actual	Spent in 2017	ETC in 2017	ETC Future Yr.(s)	Total Cost Est.	Variance Approved to Total Cost Est.
Key Capital Initiatives [2]							
CIP Implementation	1.3	0.9	0.2	0.0	0.0	1.1	0.2
IT/Cyber Security	2.3	0.6	0.8	0.2	0.5	2.1	0.2
MSR* Sustainment	3.0	-	2.0	0.7	-	2.7	0.3
Market Evolution	0.4	-	0.0	0.1	0.3	0.4	0.0
Facilities	1.4	-	0.6	0.8	-	1.3	0.1
Other Capital Initiatives	6.5	2.6	2.9	0.7	1.0	7.2	(0.7)
Life Cycle Funding	5.1	-	4.5	0.6	-	5.0	0.1
Subtotal General Capital	20.0	4.0	11.0	3.1	1.8	19.8	0.2
Major Project Capital – EMS Implementation**	31.7	22.6	6.1	0.7	-	29.4	2.3
Major Project Capital – SCC* Expansion – Implementation**	21.9	-	1.4	1.2	19.0	21.5	0.4
Total Capital	73.6	26.6	18.4	5.0	20.8	70.7	2.8

Note: Differences may exist due to rounding

** Market Systems Replacement and Re-engineering*
***Energy Management System*
**** System Coordination Centre*

General Capital Program ($ million)

Spent to September 30, 2017	11.0
Estimate to Complete (ETC) in 2017	3.1
Subtotal	14.1
AESO Board Decision Document – General Capital approved	16.9
2017 budget remaining	2.8

[2] Section Appendix I - Notes which provide a summary of financial variances or changes to the (key) capital initiatives

Appendix I - Notes

The following appendix provides further detail on major project progress for the key capital programs (e.g., approved business case or change-orders).

Key Capital Initiatives		
Reliability Program – **Energy Management System (EMS)**	**Description**	The EMS is used by System Controllers in grid operations to monitor, control and optimize the performance of the power system. The EMS is comprised of two major components the Application suite and IT Infrastructure. Both components have reached end of life and will no longer be supported by their respective vendors. In order to ensure reliable grid operations, be Critical Infrastructure Protection (CIP) compliant and have supported hardware and software, it was deemed prudent to proceed with an upgrade to the AESO EMS.
	2017 Progress	The implementation phase of the EMS Upgrade project is a multi-year project which is proceeding to plan. The project was deployed into production in Q3 2017. The project completion is expected in Q4 2017. See Business Plans 2015-2017 Appendix F: Major Projects for more information.
	2017 and 2018 Plan	Sustainment and optimization phases will follow the completion of the implementation phase and related costs will form part of the AESO's ongoing general capital program.

Key Capital Initiatives		
Reliability Program - Other Components (non-EMS)	**Description**	Grid management projects that are intended to enhance the efficiency and improve the ability to reliably run the Alberta Interconnected Electric System (AIES).
	2017 Progress	The primary focus for 2017 has been the continued phased migration of Transmission Facility Owners (TFOs) and Independent Power Producer (IPP) to the new network for the Supervisory Control and Data Acquisition (SCADA)/Wide Area Network (WAN) communications service.
	2017 and 2018 Plan	The AESO plans to continue and complete TFO and IPP migrations to the new EMS (SCADA) WAN enhancing communications.
Alberta Reliability Standards Critical Infrastructure Protection (CIP) Implementation	**Description**	Implementation of facility upgrades, changes to AESO sites and/or systems that are required to support CIP V5 implementation and compliance requirements.
	2017 Progress	Continued to implement remaining facility access, security controls and system changes required to ensure compliance readiness including: implementation of various physical security system upgrades.
	2017 and 2018 Plan	In 2017 implement remaining facility access, security controls and system changes required to ensure compliance readiness. In 2018 implement efficiencies and optimizations to the AESO's CIP process to ensure sustainability.
IT / Cyber Security Advancements	**Description**	Upgrade AESO systems and processes to reduce the risk of cyber security breaches and facilitate AESO compliance to CIP V5 requirements.
	2017 Progress	The first set of enhancements to AESO's advanced threat management capabilities have been completed. The second set of enhancements are underway and will be completed by 2017 year end. The multi-year Identity and Access Management (IAM) projects are continuing.
	2017 and 2018 Plan	Continue to advance the multi-year IAM projects. Continued implementation of additional controls to prevent, detect, respond to, and recover from incidents.

Key Capital Initiatives		
Market Systems Replacement and Reengineering (MSR) - Implementation (Sustainment)	**Description**	The MSR Implementation program is based on a multi-year phased approach designed to address the operating requirements of the AESO's market systems. Many of these systems have been stretched past their useful life and in many cases, have become increasingly difficult and costly to change and operate reliably. Focus is to sustain current market system reliability and security through medium-term measures.
	2017 Progress	Continuing medium-term sustainment measures.
	2017 and 2018 Plan	Future reengineering or replacement of the AESO's existing market systems will be part of a new market systems transition program (to be defined) with capital investment expected to start in the second half of 2018 or early in 2019. This major initiative will transition the AESO's existing market systems to support the capacity market and the Renewable Energy Program (REP) requirements. This approach allows for the coordination between the changes required due to market evolution and the changes required to address lifecycle needs of the existing market systems.
Market Evolution	**Description**	The identification, development and implementation of tools in support of market optimization and/or performance improvements. This includes system changes for wind and solar aggregated generating facility forecasting rules, and system changes to enable increased flexibility for Operating Reserve (OR) procurement. Also included are system changes to support an evolving market due to implementation of a capacity market and increased amounts of renewables.
	2017 Progress	OR procurement system changes business case completed. Based on business case review, no system changes are being pursued. Business case for system changes for Wind and Solar Aggregated Generating Facility Forecasting rules completed and approved.
	2017 and 2018 Plan	Implement system changes supporting the Wind and Solar Aggregated Generating Facility Forecasting Rules by the end of Q2 2018. Implement tools to support development of capacity market demand curve and develop high level design for capacity market auction tools.

Key Capital Initiatives		
Facilities	**Description**	Implement physical access control (security) improvements at the System Coordination Centre (SCC) to enhance security and safety for personnel. Supports SCC Expansion initiative.
	2017 Progress	Construction started in Q3 2017 and on track for completion.
	2017 Plans	Complete access control construction work at the SCC by the end of 2017.
Key Initiatives		**2017 Budget $6.4 million** **2018 Budget $4.5 million**