Quarterly Stakeholder Report
First Quarter (January – March 2023)

The purpose of the of the quarterly report is to provide stakeholders with an update on the Alberta Electric System Operator's (AESO) budget and priorities identified in its *2023 Business Plan and Budget (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 updates provided.

Priorities to Enable Transformation in 2023

	Priority	Update (Current)
1	Assess specific implications of **carbon policy** implementation mechanisms on the electricity sector to provide insights to government and industry	• Ongoing regular workshops with Ministry of Affordability and Utilities staff • Continuing monitoring of and participation in Environment and Climate Change Canada (ECCC) stakeholder process for Clean Electricity Regulation (CER) development • Consideration of potential carbon policy impacts in development of *2023 Long-term Outlook*
2	Identify required market initiatives to support **long-term sustainability and competitiveness** of the energy-only market structure, based on output from carbon policy analysis and assessments	• Market Pathways initiative initiated at AESO Stakeholder Symposium on June 27, 2023
3	Assess **different fleet scenarios** (from carbon policy analysis), and options to implement (technical requirements, market design changes, and new ancillary service products)	• Published the *AESO 2023 Reliability Requirements Roadmap* (R3) in Q1 2023 and held stakeholder session • Implemented adjustments to Load Shed Service for imports (LSSi) arming requirements for imports based on R3 findings to mitigate frequency stability risk while importing • Implementing R3 workplan • Initiating procurement design for upcoming fast frequency response service
4	Implement **Energy Storage (ES) and Distributed Energy Resources (DER) i**ntegration	• Energy Storage ISO rules filed with, and approved by, the Alberta Utilities Commission (AUC) in Q2 • Energy Storage Tariff working group collaborative engagement underway in Q2 • Published updated 2023 Plan for DER Roadmap integration activities • The AESO is engaging in policy/regulatory-related initiatives to share our AESO's principles and perspectives as they relate to mandate implications, including AUC proceeding underway for distribution facility owner (DFO) performance-based regulation

Alberta Electric System Operator

Calgary Place, 2500, 330-5th Avenue SW Calgary, AB T2P 0L4

Phone: 403-539-2450 | Fax: 403-539-2949

www.aeso.ca

@theaeso

	Priority	Update (Current)
		• The AESO is consulting on rule amendments to reduce operating reserve minimum asset capability requirements, in alignment with a recommendation from the Operating Reserve Market Review engagement
5	Streamline the **connection process**	• Process implementation is progressing as planned for time savings and efficiency • Stage 0 System Access Service Request (SASR) acceptance start date was implemented on April 3, 2023 • The AESO is working towards cluster studies implementation as planned with launch of inaugural cluster studies in September • Continuing with stakeholder engagement and alignment leading up to cluster study launch • Finalizing resource recruitment
6	Ensure **staffing requirements** can effectively deliver the AESO's priorities to enable transformation	• Formation of the AESO Strategic Integration team • Reallocation of AESO staff to deliver on priorities • Additional staff hired and being recruited to deliver on priorities (some of these costs offset by connection revenue)
7	**Manage costs** and **effectively implement policies**	• Continued focus on system optimization through use of Remedial Action Schemes, network reconfigurations, line upgrades and power flow controls, providing locational signals (such as capability maps), milestones in system planning, and assessment of dynamic line rating opportunities

Financial Update – As of March 31, 2023

Transmission Operating Costs ($ million)	2023 Actual	2023 Forecast	2022 Actual
Wires costs	480.0	479.6	444.5
Operating reserves	88.1	103.1	59.1
Transmission line losses	80.0	62.6	45.4
Other ancillary service costs	5.3	9.6	11.3
Total Transmission Operating Costs	**653.4**	**654.9**	**560.3**

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 AUC-approved tariffs and are not controllable costs of the AESO.

Year-to-date wires costs are consistent with forecast.

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.

The cost of operating reserves is impacted by actual volumes, hourly pool prices and operating reserve prices. While the average hourly pool price of $142 per megawatt hour (MWh) year-to-date is 13.6 per cent higher than the forecast of $125 per MWh, operating reserve costs are 14.5 per cent lower than forecast primarily due to lower active operating reserve costs driven by lower actual volumes. Operating reserve volumes financially settled year-to-date are 1,567 gigawatt hours (GWh) compared to the forecast of 1,718 GWh, representing an 8.8 per cent decrease. The overall decrease in operating reserve costs compared to forecast is the result of the decrease in actual volumes, which has more than offset the impact of the increase in pool price.

Transmission line losses | Transmission line losses represent the volume of energy that is lost as a result of electrical resistance on the transmission system. 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.

The cost of transmission line losses year-to-date is $17.4 million or 27.8 per cent higher than the forecast due to the impact of a 13.6 per cent higher average pool price, as well as actual line loss volumes year-to-date of 572 GWh compared to the forecast of 493 GWh, representing a 16.0 per cent increase.

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)	2023 Actual	2023 Forecast	2022 Actual
Load shed service for imports	3.0	6.6	8.0
Fast frequency response	0.1	0.3	-
Transmission must-run			
Contracted	0.3	0.6	-
Conscripted	-	0.5	1.9
Reliability services	0.7	0.7	0.7
Black start	0.7	0.7	0.6
Transmission constraint rebalancing	0.5	0.2	0.0
Total Other Ancillary Services	**5.3**	**9.6**	**11.3**

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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 requirements for arming and tripping. Year-to-date costs for LSSi are $3.6 million or 54.5 per cent lower than forecast largely due to a substantial decrease in import volumes across the British Columbia intertie.

Fast frequency response (FFR) is a fast-acting transmission reliability service that facilitates the arrest of, and recovery from, frequency decay caused by events such as the sudden loss of imports from the interties with British Columbia and Montana. This is a service adapted for new technology, such as energy storage. Two one-year pilot contracts were awarded and began providing FFR services in March 2022. Year-to-date costs for FFR are $0.2 million or 66.7 per cent lower than forecast largely due to a substantial decrease in import volumes across the interties.

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 TMR services are 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). Contracted TMR costs year-to-date are $0.3 million or 50.0 per cent lower than forecast, primarily due to a decrease in availability payments. Conscripted TMR costs year-to-date are nil and are primarily a reflection of the new TMR contract put into place, reducing the need for conscripted TMR services in the northwest region of Alberta.

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.

Black start services are provided by generators that can restart their generation facility with no outside source of power. In the event of a system-wide blackout, black start services are used to re-energize the transmission system and provide start-up power to generators that 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. Transmission constraint rebalancing costs year-to-date are $0.3 million or 150.0 per cent higher than forecast due to significant transmission constraint rebalancing events in February and March.

Other Industry Costs ($ million)	2023 Actual	2023 Budget	2022 Actual
AUC fees – Transmission	2.1	2.5	1.2
AUC fees – Energy Market	1.5	2.0	1.0
WECC/NWPP/NERC costs	0.7	0.7	0.6
Regulatory process costs	0.5	1.1	1.3
Total Other Industry Costs	**4.8**	**6.3**	**4.1**

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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), Northwest Power Pool (NWPP) and North American Electric Reliability Corporation (NERC) membership fees and regulatory process costs and non-compliance penalties. 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.

Other industry costs year-to-date are $1.5 million or 23.8 percent lower than budget, primarily due to the timing of AUC fees and regulatory process costs, both of which are expected to increase over the remainder of the year.

General and Administrative Costs ($ million)	2023 Actual	2023 Budget	2022 Actual
Staff costs	19.5	20.3	19.4
Contract services and consultants	0.6	1.3	0.6
Facilities	1.2	1.1	1.0
Administration	0.9	1.3	0.8
Computer services and maintenance	2.6	2.6	2.6
Telecommunications	0.3	0.3	0.3
Total General and Administrative Costs	**25.1**	**26.9**	**24.7**

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General and administrative costs year-to-date are $1.8 million or 6.7 percent lower than budget, primarily due to the timing of planned hires (impacting staff costs), the timing of initiatives requiring consulting and legal services (impacting contract services and consultants), and the timing of travel, training and meals (impacting administration). Current shortfall to budget is expected to be realized over the remainder of the year.

Amortization and Depreciation and Borrowing Costs ($ million)	2023 Actual	2023 Budget	2022 Actual
Amortization of right-of-use assets, intangible assets and depreciation of property, plant and equipment	**5.7**	**5.9**	**6.8**
Borrowing costs	**0.2**	**0.2**	**0.2**

Amortization and depreciation costs year-to-date are $0.2 million or 3.4 per cent lower than budget due to the impact of a rent reduction on the amortization of some right-of-use assets.

Borrowing costs year-to-date are consistent with budget.

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Capital Expenditure Update – As of March 31, 2023

Capital Program ($ million)	Total Project Approved	Prior Year(s) Actual	Spent in 2023 to-date	ETC in 2023	ETC Future Yr.(s)	Total Cost Est.	Variance Approved to Total Cost Est.
Strategic-Related Initiatives							
Enabling Transformation	10.2	3.3	1.1	3.4	1.1	8.9	1.3
Energy Management System (EMS) Sustainment	16.8	9.2	1.9	5.7	-	16.8	0
Critical Initiatives							
Business System Modernization	0.6	0.3	0.1	0.1	0.1	0.7	0
Cyber Security and Critical Infrastructure Protection (CIP)	1.4	-	0.2	1.2	-	1.4	0
Other Capital Initiatives & Lifecycle Funding	13.8	2.4	2.3	6.9	0.8	12.4	1.4
Total Capital	**42.8**	**15.2**	**5.5**	**17.4**	**2.0**	**40.1**	**2.7**

Numbers may not add due to rounding

General Capital Program ($ million)	
Spent to Date March 31, 2023	**5.5**
General Capital Approved	**25.6**
Remaining Budget	**20.1**