



2022 Long-term Transmission Plan *Stakeholder Information Session*

March 3, 2022

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OUR ENGAGEMENT PRINCIPLES

Inclusive and Accessible

Strategic and Coordinated

Transparent and Timely

Customized and Meaningful

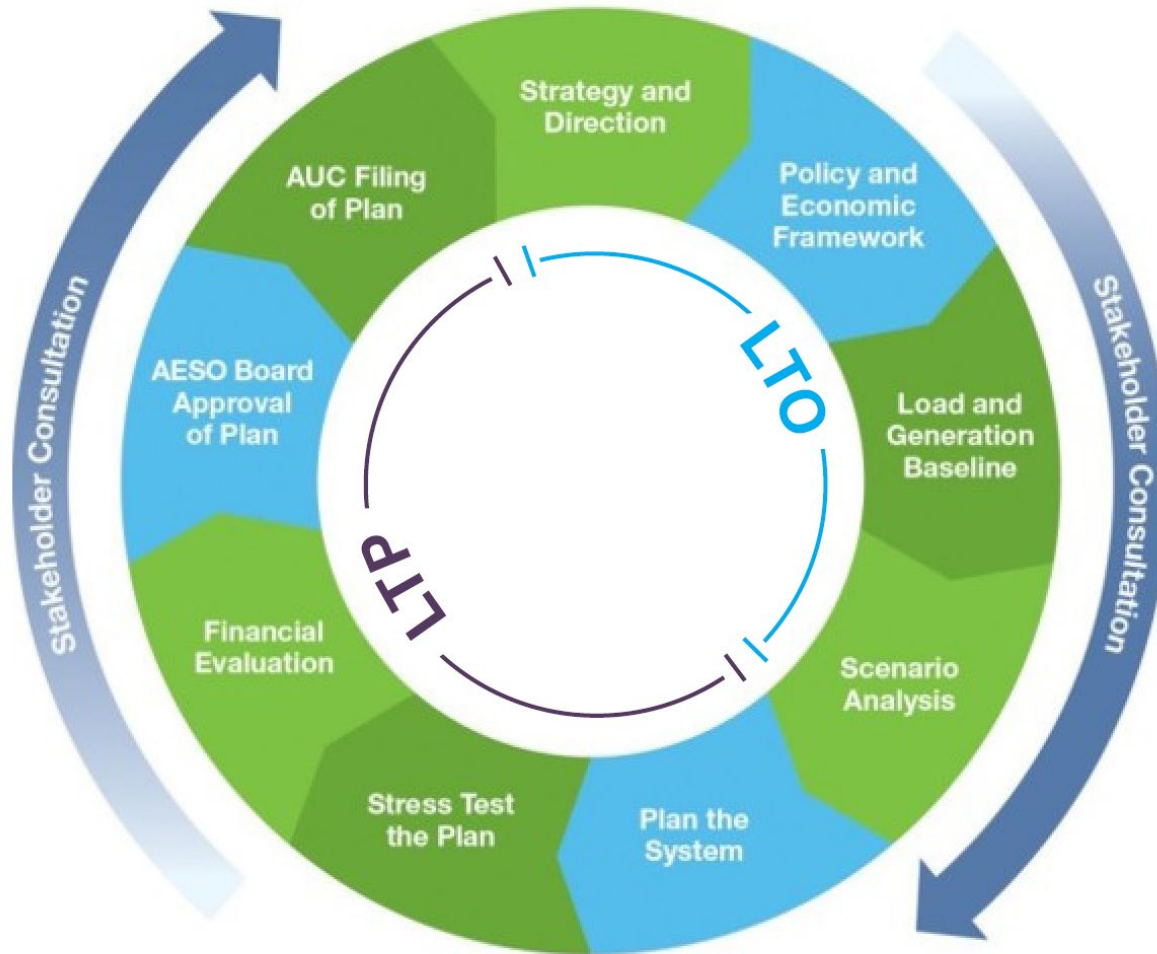
- Welcome/introductions
- The 2022 Long-Term Transmission Plan (LTP): highlights
- The transmission planning process
- The 2021 Long-Term Outlook
- Near-term developments by region
- Longer-term scenarios
- Inverter-based resources and energy storage
- Cost impact of the 2022 LTP
- Questions and answers

- Meets our legislative obligations for long-term planning, focused on ensuring reliability and a fair, efficient and openly competitive (FEOC) market
- Integrated with the 2021 Long-term Transmission Outlook (LTO) scenarios
- Utilizes a risk-based planning approach to identify a range of potential future transmission developments and timing
- Employs optimization of the existing transmission system before additional infrastructure is considered
- Identifies **potential projects** that may be needed some time in the future depending on which scenario path unfolds; does not centrally plan supply
- Includes a future cost range (low/high) dependent on future scenario
 - Defers \$1B of transmission project by several years
 - Potentially adding \$1 - \$2 per month to average residential customer if all transmission projects are built

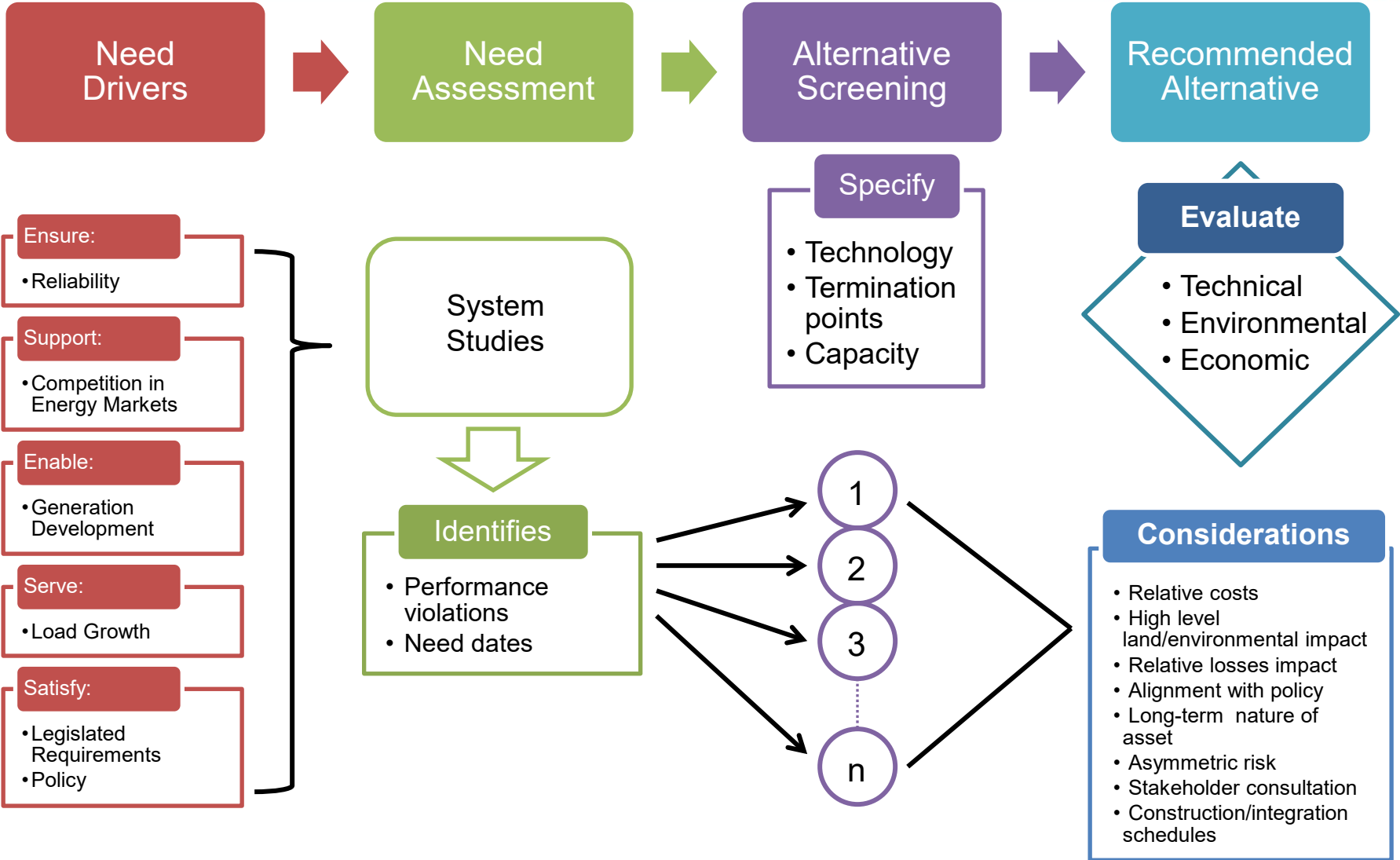
The Transmission Planning Process

- The 2022 LTP seeks to optimize the existing transmission system by identifying potential opportunities to delay large transmission developments while meeting reliability needs
 - Remedial action schemes, network reconfigurations, line rating upgrades, power flow controllers
- The 2022 LTP utilizes a risk-based approach
 - Based on the 2021 LTO scenarios to assess broad range of future states
 - Incorporates coincident factors between load and generation profiles of wind, solar, and other generations
 - Assesses sensitivities of key variables on how they impact need for potential transmission development
 - Identifies a range of possible transmission development outcomes
- Transmission developments are linked with the key drivers that influence the timing of the need
- Meets the planning obligation for congestion in the legislation

Integrated LTO/LTP Planning Cycle



Transmission Need Approval Process



Projects identified in the 2022 LTP require regulatory approval

The 2021 Long-Term Outlook

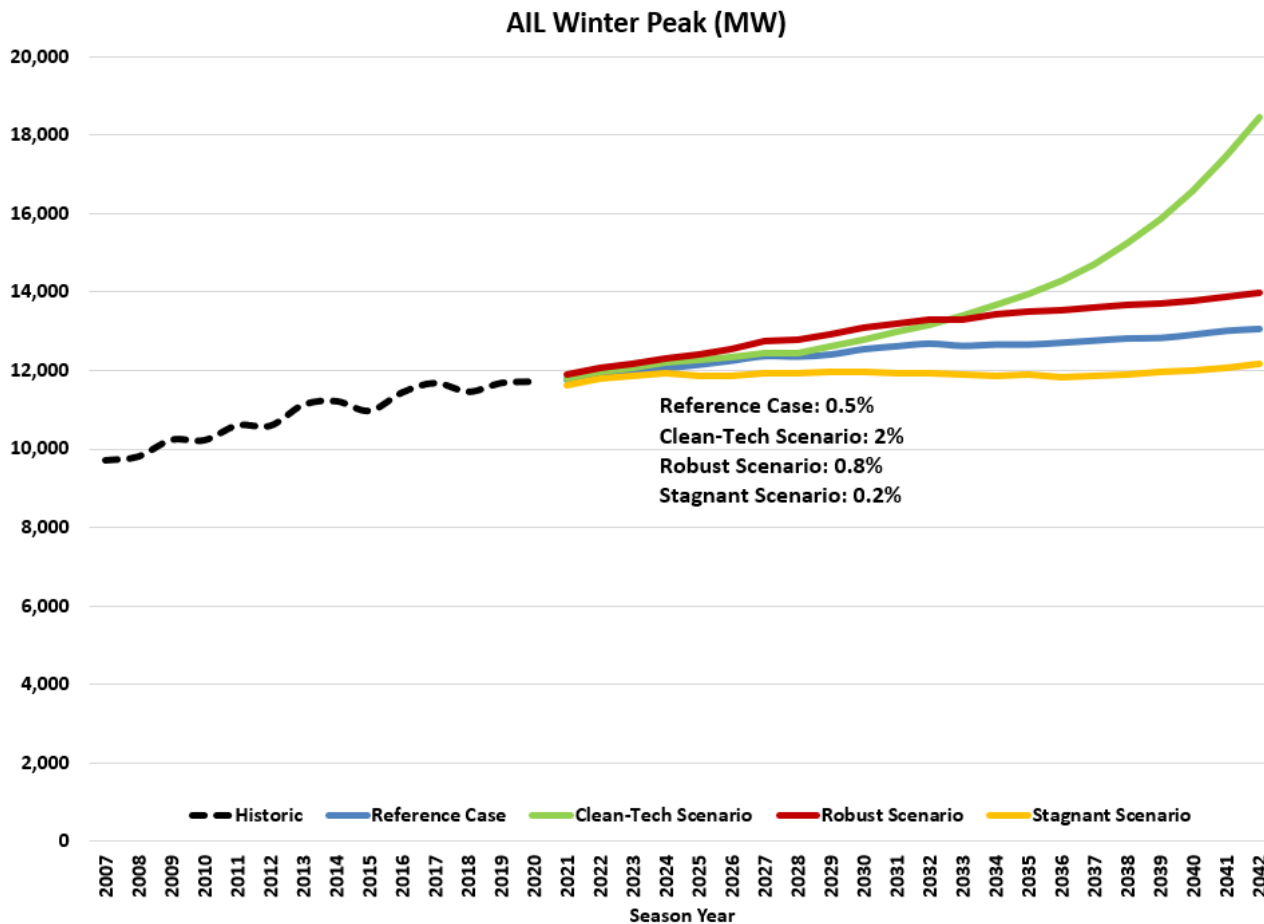
2021 Long-term Outlook (LTO) Scenarios

- 2021 LTO contains a comprehensive set of scenarios to quantify uncertainties around economic growth, technology changes and environmental policy
- The AESO continually reviews forecasts as economic, policy and other drivers evolve

Scenario	Narrative	Load	Supply
Reference Case	Based on most recent intelligence; changes are incremental and aligned with current understanding of policy, economic expectations, technology landscape	Drivers: economic recovery by 2022 and IHS outlook for energy sector (recovery in 2021)	Based on current policies, technology costs, industry trends (corp. power purchase arrangement (“PPAs”), gas entries). Near term additions based on certainty criteria, long term additions based on economics.
Clean-Tech (Energy Transformation)	Decarbonization policy and cost reductions in renewables accelerate grid changes toward low-emissions and distributed energy resources (“DER”) technologies; models \$170/tonne carbon price	Different load profile than Ref Case – higher electric vehicle load, higher DER, potential changes to industrial mix due to diversification; oil sands outlook is lower than Ref Case	Shift towards more renewables (transmission and distribution connected), fewer carbon intensive technologies; higher cogeneration due to boiler replacements
Robust Global Oil & Gas Demand	The most optimistic scenario for Alberta’s energy sector (add projects to fill major pipelines plus crude by rail)	Higher than Ref Case due to O&G growth (incl. condensates in NW) and more market access (pipelines) while maintaining 100 MT emissions cap	Higher cogeneration, and clean natural-gas generation
Stagnating Global Oil & Gas Demand	Economic stagnation and no further investment in the oil and gas sector changes AB economic future	Oil sands production remains flat post 2021 recovery; economic inputs reflect lower energy sector, including permanent loss of load	Clean natural-gas generation is built to replace retired facilities, but growth is muted

Load: Scenario Comparison

- The Reference Case is flanked by the Robust and Stagnant O&G Demand scenarios
- The Clean-Tech forecast illustrates the potential cumulative impact of EV load penetration in the 2030s



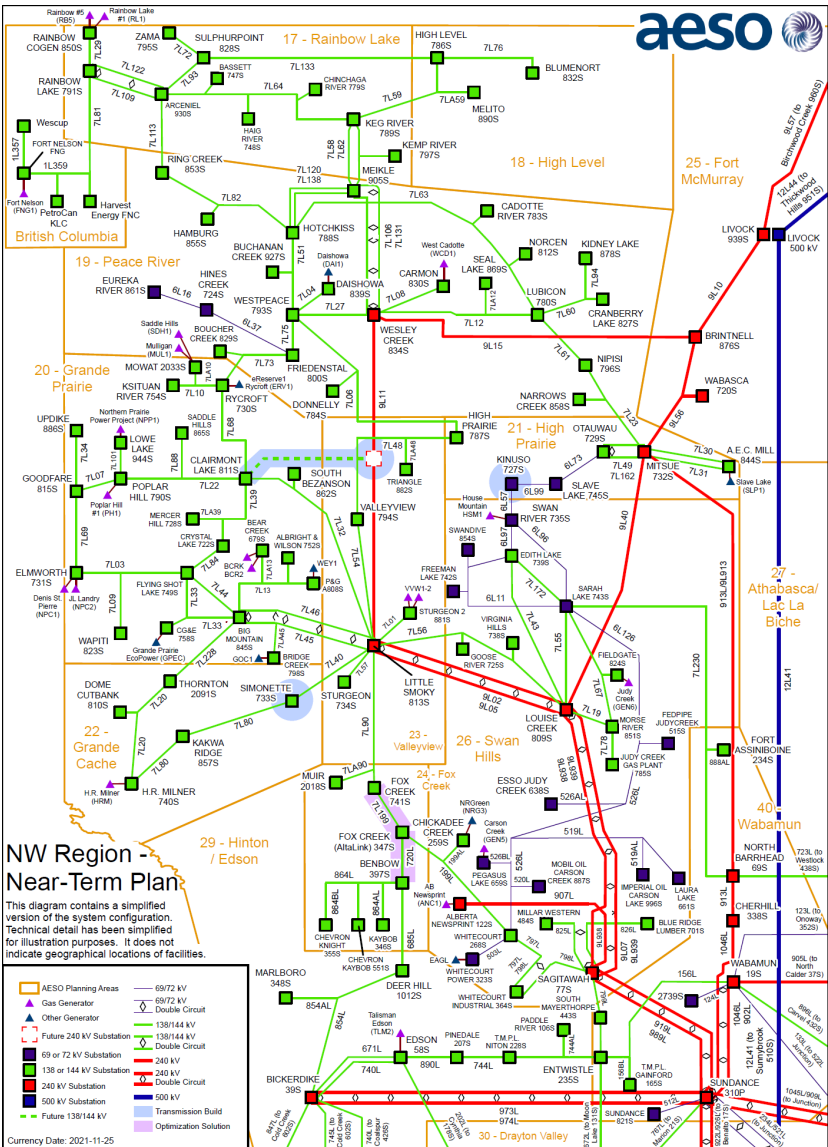
Generation: Scenario Comparison

	Total Capacity (MW)	Change in Capacity (MW)			Total Capacity (MW)	Change in Capacity (MW)		
	Reference Case	Clean-Tech	Robust Global Oil and Gas Demand	Stagnant Global Oil and Gas Demand	Reference Case	Clean-Tech	Robust Global Oil and Gas Demand	Stagnant Global Oil and Gas Demand
Year	2031	2031	2031	2031	2041	2041	2041	2041
Average Load	10,483	(217)	543	(593)	10,615	781	897	(903)
Distribution-Connected (< 5 MW) Generation								
Solar	396	628	–	–	729	1,321	–	–
Gas	123	26	–	–	161	50	–	–
Wind	41	7	–	–	48	11	–	–
Total Distribution-Connected (< 5 MW) Generation	560	661	–	–	939	1,382	–	–
Grid-Connected and Distribution-Connected (5 MW or greater) Generation								
Wind	4,617	(120)	(90)	(710)	4,907	540	(120)	(750)
Solar	1,054	910	160	–	1,254	1,680	320	–
Simple Cycle	1,351	99	–	47	1,461	515	(140)	233
Combined Cycle	2,648	2,174	–	–	3,772	737	–	(479)
Coal to Gas Conversion	4,122	(3,187)	–	(2,387)	–	–	–	–
Coal	–	–	–	–	–	–	–	–
Cogeneration	6,579	–	720	(585)	6,669	135	990	(675)
Other	423	20	–	–	423	100	–	–
Hydro	894	–	–	–	894	–	–	–
Energy Storage	100	1,030	–	–	150	1,370	–	–
Total Grid-Connected and Distribution-Connected (5 MW or greater) Generation	21,788	926	790	(3,636)	19,530	5,077	1,051	(1,672)

Near-Term Developments

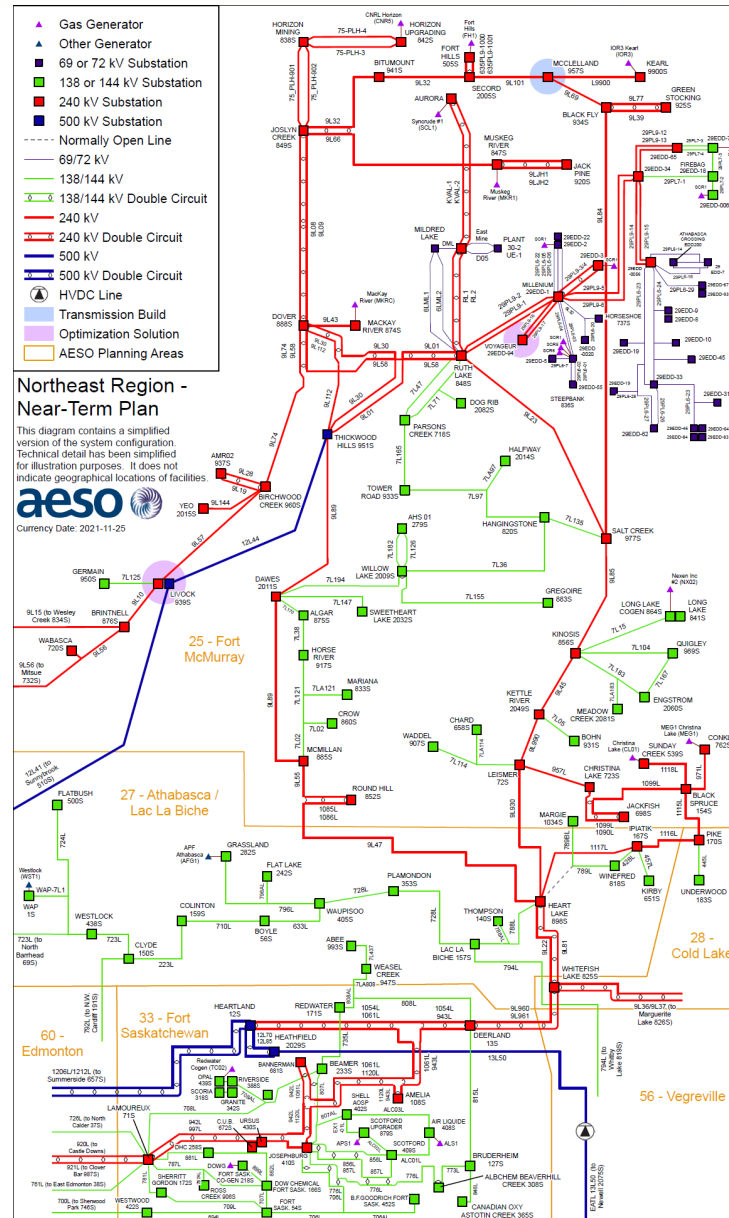
Northwest & Northeast

- A transmission line from 9L11 to Grande Prairie – Load serving
- Little Smoky transformation capacity
- Increase capacity of existing lines in the Fox Creek area
- Voltage support projects



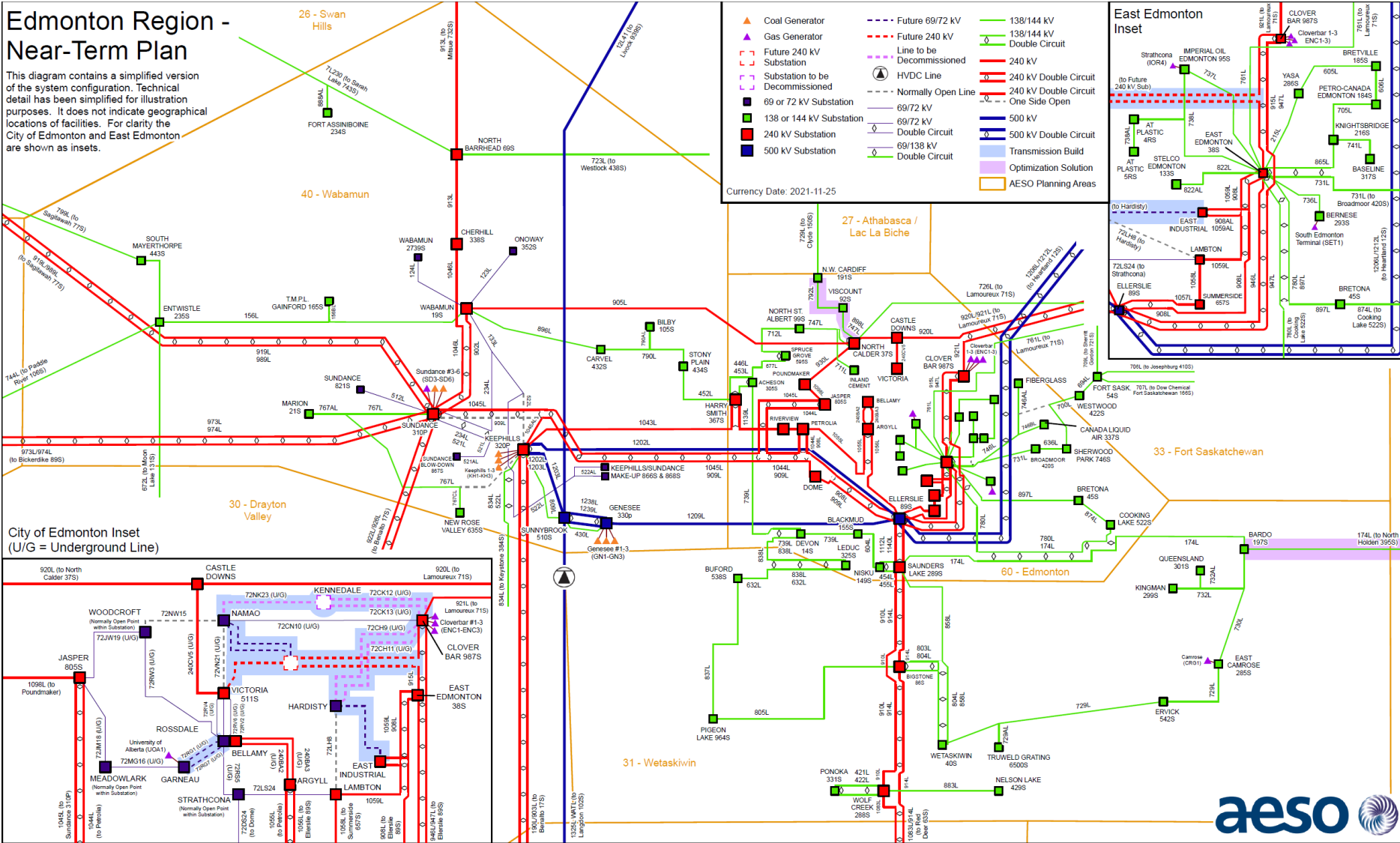
- Optimization solutions in place, including RAS and utilizing the existing PST when required, can help integrate large generation addition in the NE

- Voltage support at McClelland substation



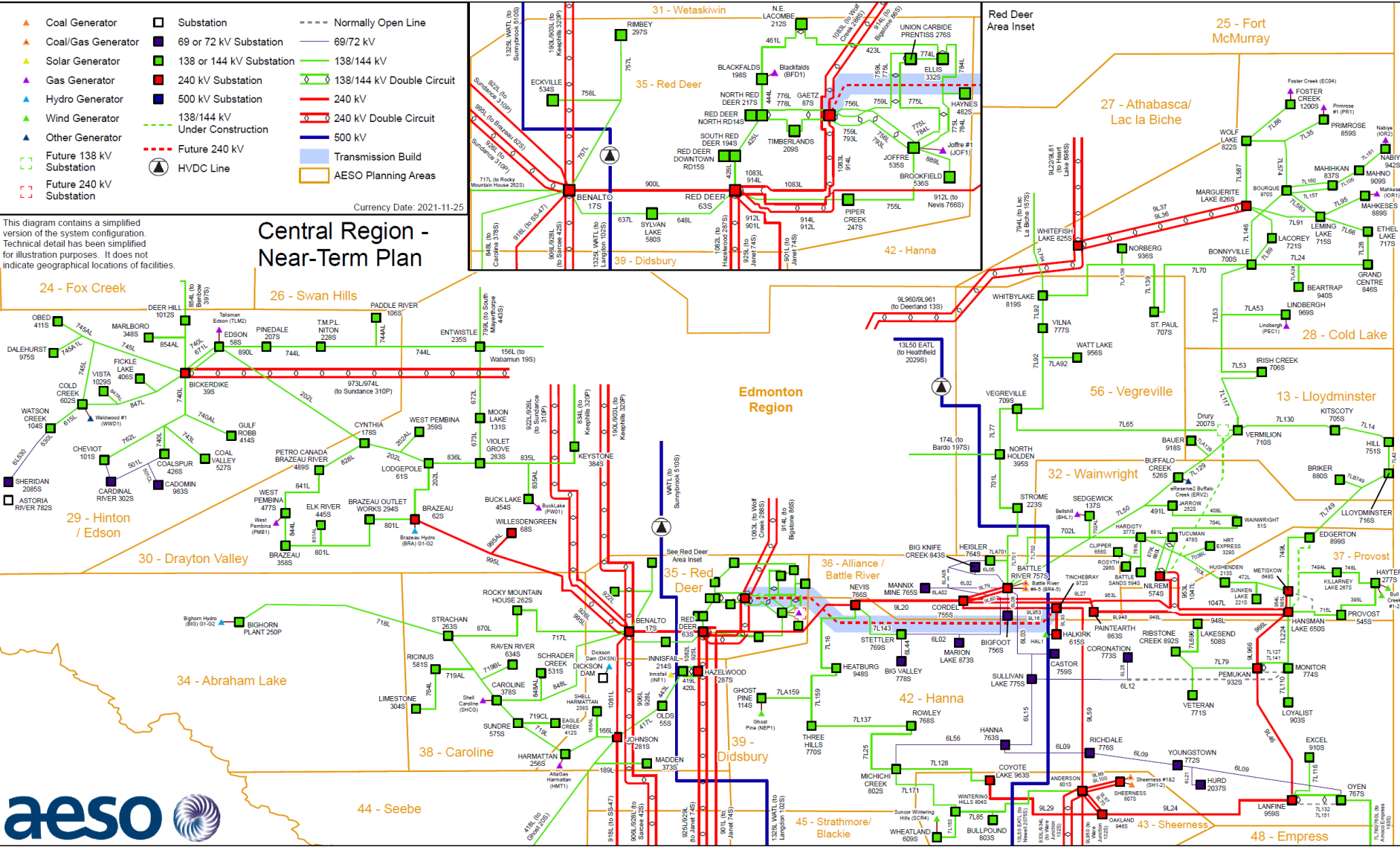
Edmonton Region - Near-Term Plan

This diagram contains a simplified version of the system configuration. Technical detail has been simplified for illustration purposes. It does not indicate geographical locations of facilities. For clarity the City of Edmonton and East Edmonton are shown as insets.



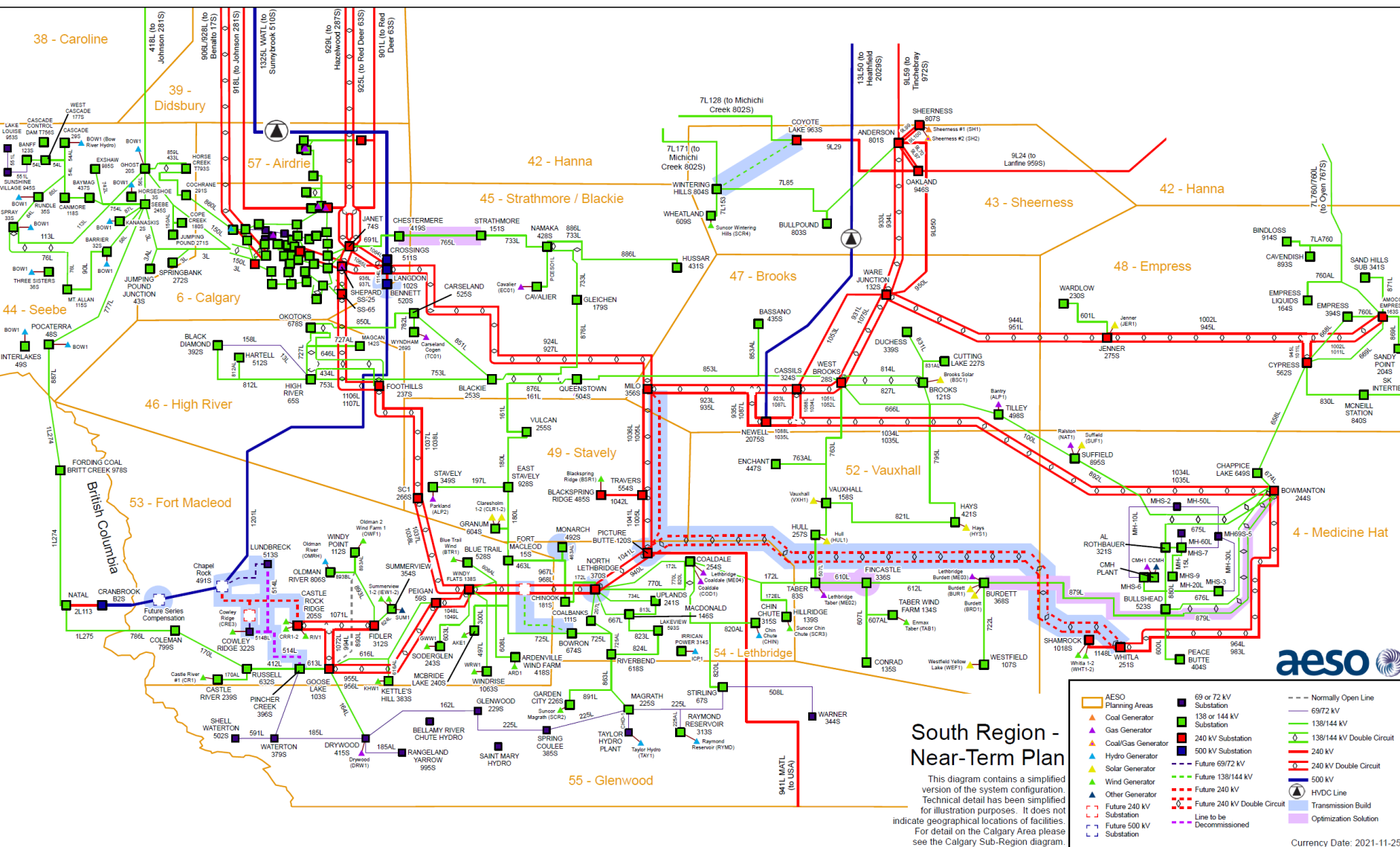
Currency Date: 2021-11-25

- City of Edmonton Project
 - Provide 240 kV supply from 915L
 - Replace Kennedale with a 240 kV sub (East Terminal)
 - Feed Namao from East Terminal
 - Replace aging assets and increase load serving capacity
- Longer-term plan in the City of Edmonton includes extending the 240 kV system supply from East Terminal to Victoria as well as Garneau and Hardisty upgrades
- Line rating increases



- PENV (NID approved)
 - New Edgerton – Hansman Lake line
 - New Nilrem – Drury line (Drury is adjacent to Vermilion)
 - Serves load and provides generation integration capability

- CETO (NID approved)
 - Two circuits from Tinchebray (near Battle River) to Gaetz (near Red Deer)
 - Provides generation integration capability



South Region - Near-Term Plan

This diagram contains a simplified version of the system configuration. Technical detail has been simplified for illustration purposes. It does not indicate geographical locations of facilities. For detail on the Calgary Area please see the Calgary Sub-Region diagram.

- ▭ AESO Planning Areas
- 69 or 72 kV Substation
- 138 or 144 kV Substation
- ▲ Gas Generator
- ▲ Coal/Gas Generator
- ▲ Hydro Generator
- ▲ Solar Generator
- ▲ Wind Generator
- ▲ Other Generator
- ▲ Substation
- ▲ Future 500 kV Substation
- Normally Open Line
- 69/72 kV
- 138/144 kV
- 240 kV
- 240 kV Double Circuit
- 240 kV Double Circuit
- 240 kV
- 240 kV
- 240 kV Double Circuit
- Future 240 kV
- Future 138/144 kV
- Future 240 kV
- Future 240 kV Double Circuit
- Future 240 kV
- Future 500 kV Substation
- Decommissioned
- HVDC
- Transmission Build
- Optimization Solution

- Southeast 240 kV transmission reinforcement
 - A new 240 kV line from Whitla or Bowmanton
 - Provides generation integration capability in the southeast
- Lethbridge area transmission reinforcement
 - New 240/138 kV sub and transmission line
 - Increases load serving capability
- Chapel Rock – Pincher Creek
 - Establish a new 500/240 kV Chapel Rock sub on 1201L
 - New 240 kV line from Chapel Rock to Pincher Creek
 - Provides generation integration capability in the southwest
- Sheerness area transmission reinforcement
 - New 138 kV line from Wintering Hills to Coyote Lake
 - Provides generation integration capability in the Sheerness area

Longer-Term Scenarios

- Renewable generation capacity growth
 - SE, CETO, CRPC may be advanced
- Electric vehicles contribute to load growth in urban areas
 - Distribution system likely to be stressed first
 - New transmission to support EV is not expected for 10+ years
- DER growth
 - Partly rooftop solar
 - Offsets EV demand to some extent

- Stagnating O&G
 - No incremental needs likely
- Robust O&G
 - 9L74 upgrade (possible)
 - FMM East 500 kV project (less likely)

Inverter-based Resources and Energy Storage

- Increase in inverter-based resources (IBRs) such as wind and solar and the retirement of synchronous machines lead to decline in system inertia
- A smaller system inertia results in larger rate of change of frequency (RoCoF)
 - Require faster/larger mitigation to maintain acceptable frequency
 - Protection relays may trip in response to RoCoF
- IBRs also contribute a much lower short circuit level (SCL) compared to synchronous machines. Lower SCL can impact IBRs' ability to provide expected real and reactive power, potentially leading to issues including voltage stability.
- The AESO is monitoring the situation, and will publish a detailed Flexibility report later in 2022
- Energy storage (ES) penetration levels are rising in Alberta with 60 MW connected at the end of 2021
 - AESO will continue to engage stakeholders as ES evolves
- AESO also considers all appropriate alternatives, including ES, as part of its planning process
 - AESO will engage stakeholders to share information about alternatives considered for material system NIDs

Cost Impact of the 2022 LTP

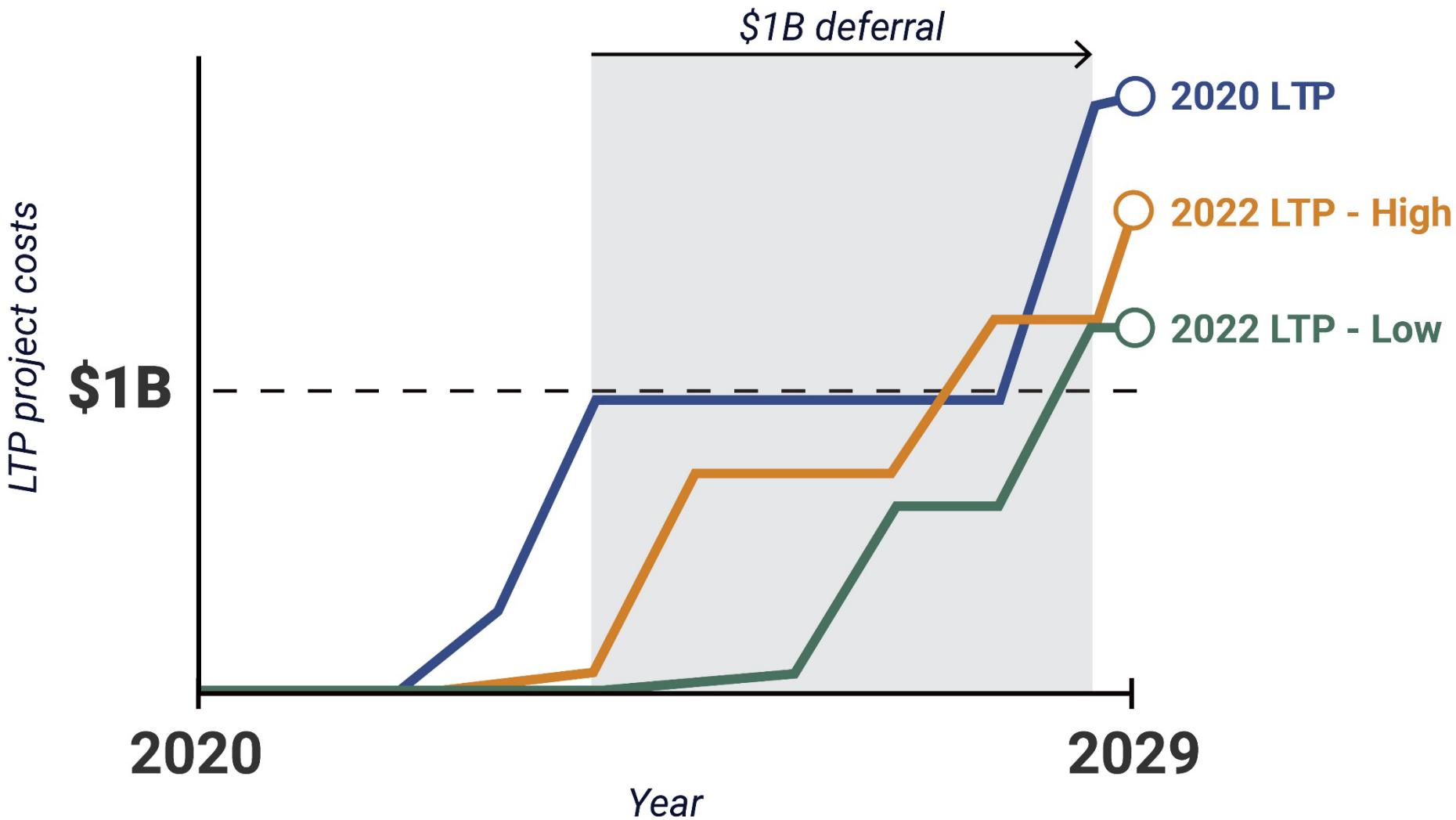
Major transmission projects

#	Type	Project	Driver	LTP. Cost Estimate (\$M)	Earlier Transmission Requirement year	Later Transmission Requirement Year
1	NID Approved	Rycroft: static var compensator (“SVC”) at Rycroft, in construction	Load in Grande Prairie	\$40	2023	2023
2	NID Approved	PENV: two 240 kV lines in two stages, initially operated at 138 kV	Generation in Central East and Southeast & load in Central East	\$293	2025	2027
3	NID Approved	CETO: one new 240 kV line between Tinchebray and Gaetz	Generation in Central East and Southeast	\$310	2025	2027
4	Near Term	Vauxhall: one new 138 kV line or power flow control device	Generation in Vauxhall and Medicine Hat areas	\$15	2024	2024
5	Near Term	City of Edmonton: new 240/72 kV sub and new 240 kV & 72 kV lines for the Kennedale area	Load in the City of Edmonton	\$120	2025	2029
5b	Near Term Deferrable	City of Edmonton: new 72 kV lines for Hardisty and Garneau and 240 kV line between Kennedale and Victoria	Load in the City of Edmonton	\$200	2042	2042
6	Near Term	SE: new 240 kV line from Whitla to Milo and substation expansion (one of three options under consideration)	Generation in Southeast	\$450	2028	2029

Major transmission projects (2)

#	Type	Project	Driver	LTP. Cost Estimate (\$M)	Earlier Transmission Requirement year	Later Transmission Requirement Year
7	Near Term	Lethbridge: new 240/138 sub and new 138 kV line	Load in Lethbridge	\$40	2028	2029
8	Near Term Deferrable	MATL back-to-back direct current (DC) converter	Intertie	N/A	2030	2034
9	Near Term Deferrable	Alberta–B.C. intertie restoration: series compensation and transformer upgrade	Intertie	\$100	2030	2034
10	Near Term Deferrable	CRPC area transmission: new 500/240 kV sub, new 240 kV line and SVC	Generation in Southwest	\$400	2030	2034
11	Near Term Deferrable	Sheerness: new 138 kV line from Wintering Hills to Coyote Lake	Generation in Sheerness area	\$35	2030	2034
12	Near Term Deferrable	Grande Prairie (GP) plan: new 240 kV line from 9L11 to Clairmont and new sub at 9L11	Load in Grande Prairie	\$120	2030	2034
13	Long Term	240 kV NE plan: upgrade 9L74	Cogeneration in Fort McMurray	\$60	2037	2042

2022 LTP defers \$1B by several years compared to 2020 LTP



Thank you