2024 Long-term Outlook

Preliminary Update

November 15, 2023

Public

AESO Stakeholder Engagement Framework

The Evolving Long-term Outlook

- On August 16, 2023, the AESO gave notice to stakeholders
  - In view of evolving carbon policies and regulations impacting the development of a carbon-neutral, reliable and affordable grid, the AESO is re-evaluating the scenarios in the Long-term Outlook (LTO)
  - The primary change is the inclusion of a Decarbonization by 2050 preliminary reference case
- The AESO is requesting stakeholder feedback on the inputs to the updated Decarbonization by 2050 case and Decarbonization by 2035 scenario
  - In addition to these slides, a fulsome dataset is included with a PowerBI dashboard to provide a visual
- The final LTO report will be released in the first half of 2024

Updated Purpose and Objectives

- The purpose of this release is to update and engage stakeholders in a review of the AESO's draft modelling around the 2024 LTO Preliminary Results, provide clarification and share next steps and timing.
- Specific objectives include:
  - Present the updated preliminary reference case and scenario modelling results
  - Provide clarification around current assumptions and scenario framework
  - Include a detailed graphical PowerBI dashboard and supporting data file
  - Seek additional stakeholder written feedback prior to the AESO finalizing its modeling and analysis and moving forward with scenario development
  - The forecast models the current market construct and is not intended to provide market design solutions

Preliminary 2024 LTO Reference Case

Public

The Big Picture

- The demand and supply forecasts hinge upon provincial and federal policy and supports; risks to this forecast focus on such policies, supports, costs, technology and timing
- Load growth is much higher than more recent LTO forecasts; but not a doubling or tripling by the end of the 20-year forecast period
  - Electric vehicle load management mitigates some of the peaks
- Changes to generation remain similar to the June 2023 preliminary assessment through 2035
  - Significant growth in renewables due to policies, supports and corporate appetite for renewable PPAs
  - Large efficient thermal generation commissioning through 2024 will result in less efficient units retiring, mothballing or functioning as long lead-time (slow ramping) assets
  - Retrofits of existing combined-cycle generation with CCUS starting in the late 2020's results in similar significant emissions reductions for both the 2035 Decarbonization and 2050 Decarbonization scenarios
- Post- 2035, firm generation additions (Combined Cycle and Nuclear SMR) are more significant to meet a combination of continued load growth and regulated retirements of the remaining coal to gas converted generating units
  - Managed load mitigates some of the resource adequacy challenges in 2035
  - Initial resource adequacy assessments highlight challenges starting in 2038; exacerbated in the 2035 Decarbonization scenario
- Energy storage growth remains the same as the June 2023 assessment; driven by opportunities in ancillary markets and not arbitrage opportunities
- As Alberta continues to decarbonize, a focus on system reliability and affordability is paramount for ratepayers, stakeholders and the AESO

Recent Model Enhancements

- Recent model enhancements include
  - Electric vehicle (EV) load shifting (load management) has been integrated into load forecast to reflect the potential to mitigate EV coincidental load peaks when penetration levels increase
  - Nuclear cost forecasts have been reduced in the long term, to align with “next-of-a-kind” plant expectations by 2050
  - CER parameter clarification (Gazette I)
    - Revised date of application for coal-to-gas converted units to align with examples provided by Environment and Climate Change Canada (ECCC)
- The AESO has developed a Decarbonization by 2050 preliminary reference case and updated the Decarbonization by 2035 scenario

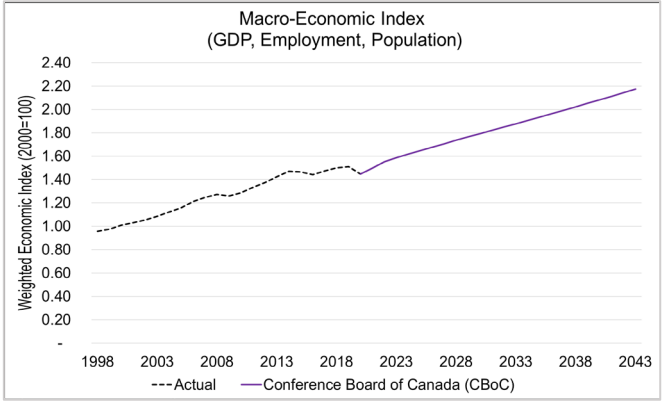
2024 LTO – Preliminary Alberta Internal Load Forecast

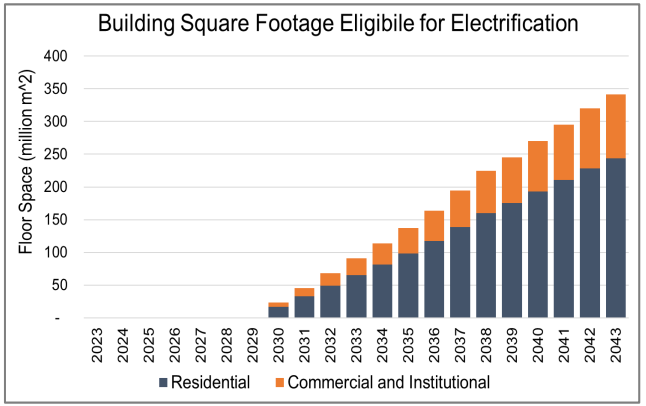
Key Messages

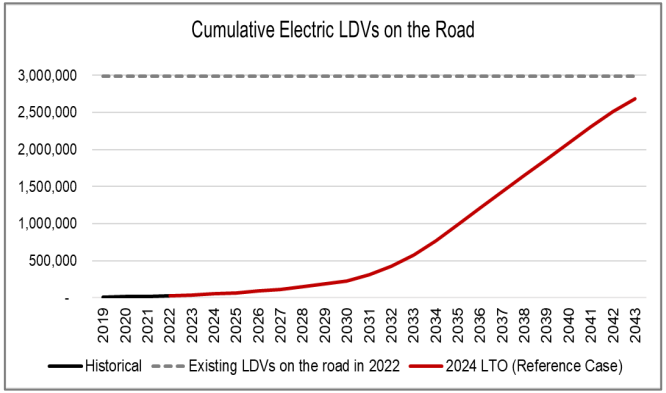
- Since the preliminary results were shared in June 2023, the AESO has revised key assumptions of the Reference Case forecast and developed a High Electrification scenario to capture upside risks
  - Developments toward managing electric vehicle charging loads has been updated in the Reference Case and included in High Electrification
  - Supply mix scenarios and resource adequacy sensitivities only rely on the Reference Case load forecast
- Both forecast scenarios point to an increase in Alberta internal load (AIL)
  - The near-term is mostly driven by strong macroeconomic factors, including oilsands production and new load connection projects; long-term growth fueled by electrification of different sectors of the economy (transportation and buildings), and growth in nascent industrial sectors (hydrogen)
  - Doubling or tripling of AIL is not expected: compared to 2022, the 2043 peak demand forecast is expected to reach 16 GW (a 32% increase) in the Reference Case and 20 GW (a 64% increase) in the High Electrification scenario, assuming electric vehicle (EV) charging is managed
- Additional insights
  - The compound effect of distributed solar energy with the electrification of vehicles and buildings will lead to frequent and acute ramps of AIL, potentially adding more challenges to overall system flexibility
  - Alberta is expected to remain a winter peaking grid due to extreme temperatures and additional load requirements from EVs and building heating

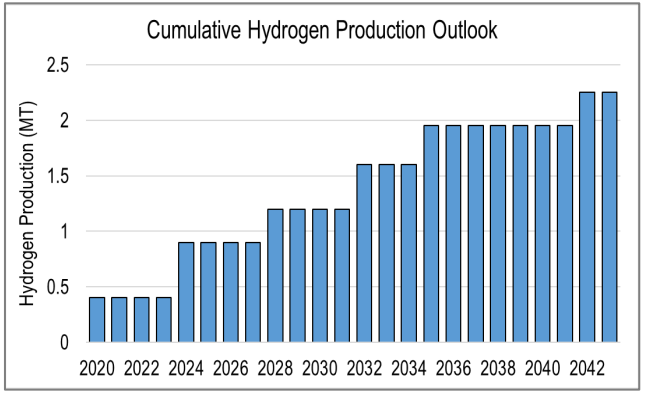
AIL drivers becoming varied

- AIL drivers are becoming more diverse over the next two decades
  - In addition to macroeconomics, demographics and energy factors, load will be increasingly driven by multi-sectoral trends driven by decarbonization goals



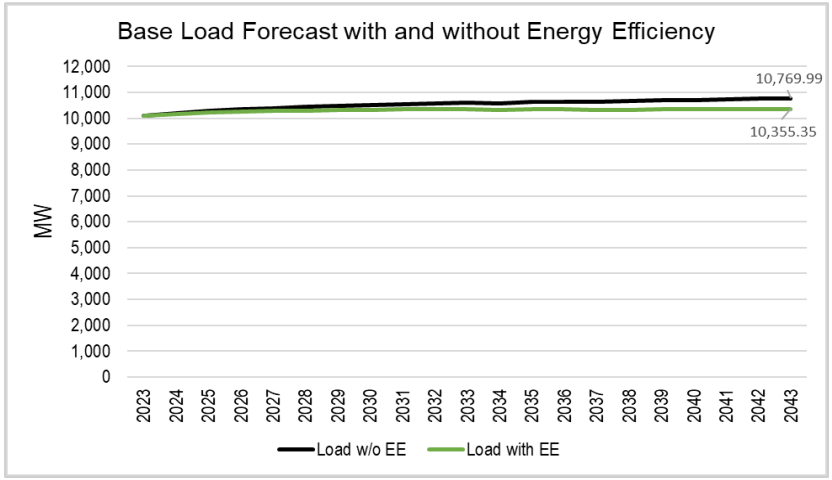




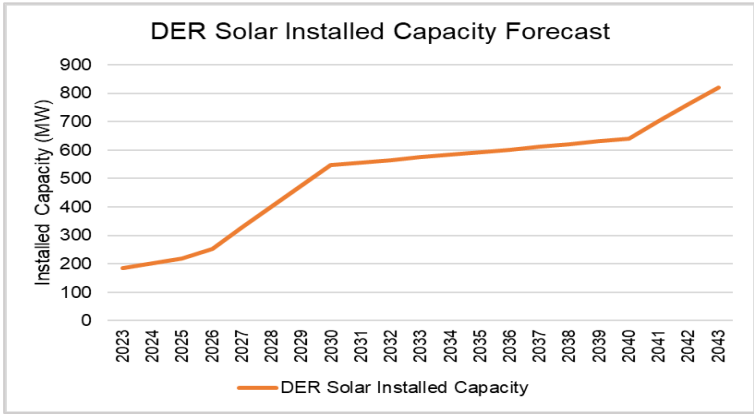


AIL Growth offsets

- AIL Growth will be offset by energy efficiency and DER
- An improved and more robust energy efficiency methodology was designed for the 2024 LTO
  - Focus is on avoided load in residential and commercial sectors
- Cumulative impact of energy efficiency gains is approximately 415 MW by 2043



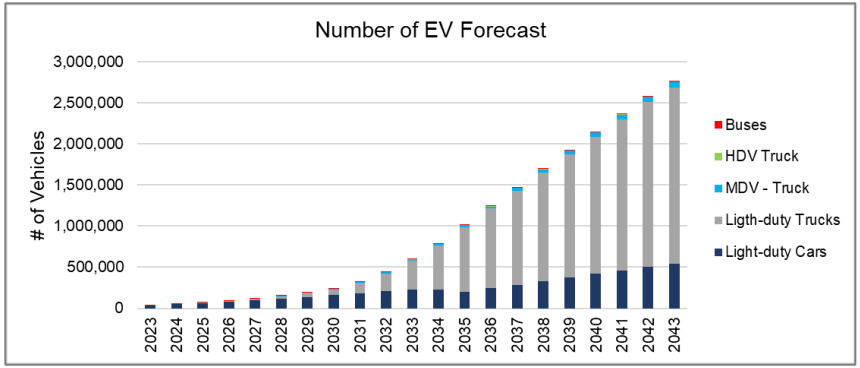
- Sub-5 MW Solar DER adoption is expected to increase as capital costs of solar panels continue to decline and government supports continue
  - Concentration is still expected to remain in Alberta's largest cities and southern municipalities
  - Gas and wind sub-5 MW adoption will remain minimal
- Installed solar capacity is expected to increase to 821 MW by 2043

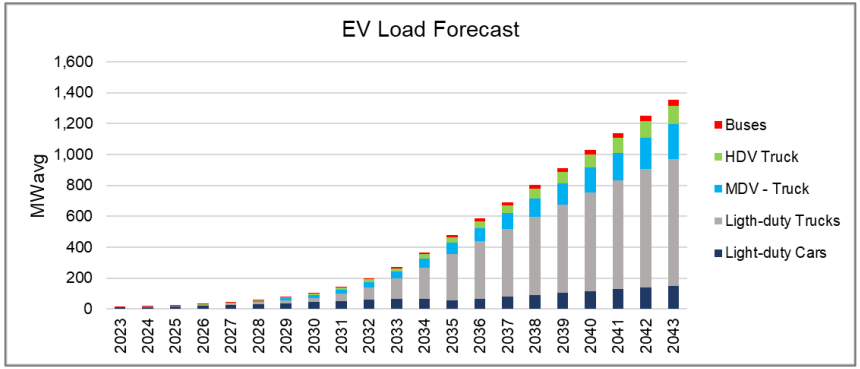


EV Adoption to Increase Exponentially

Vehicle Type	Percentage of New Sales
Light-duty	10% by 2026, 20% 2030, 100% by 2035
Medium-duty	1% by 2026, 30% by 2043
Heavy-duty	0.5% by 2026, 20% by 2043
Bus	20% by 2030, 65% by 2040

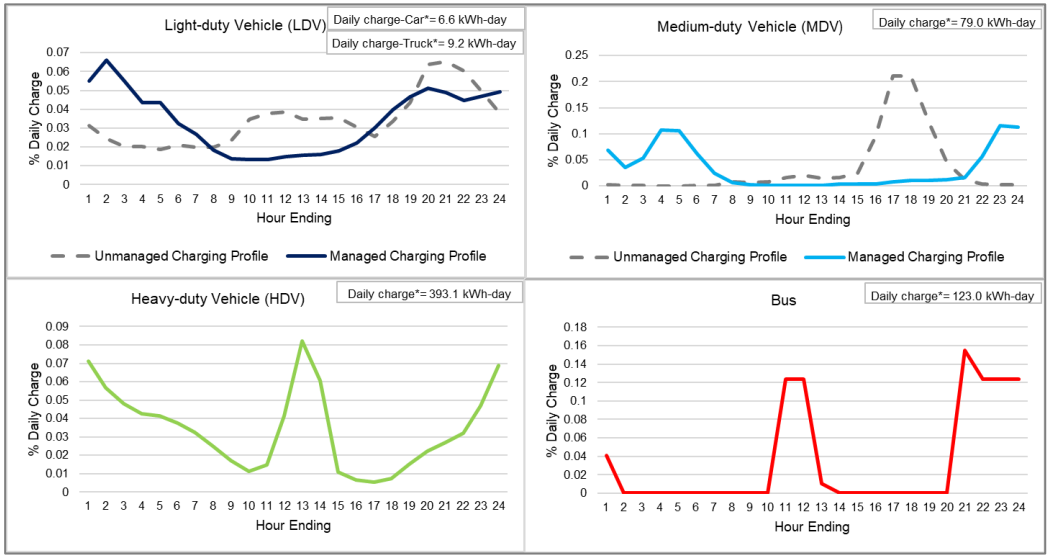
- EV sales assumptions factor in the absence of provincial subsidies.
  - More aggressive assumptions are tested in the High Electrification scenario.
- By 2043, the number of vehicles and the load are projected to increase significantly, reaching approximately 2.8 million vehicles and 1,350 MW on average.

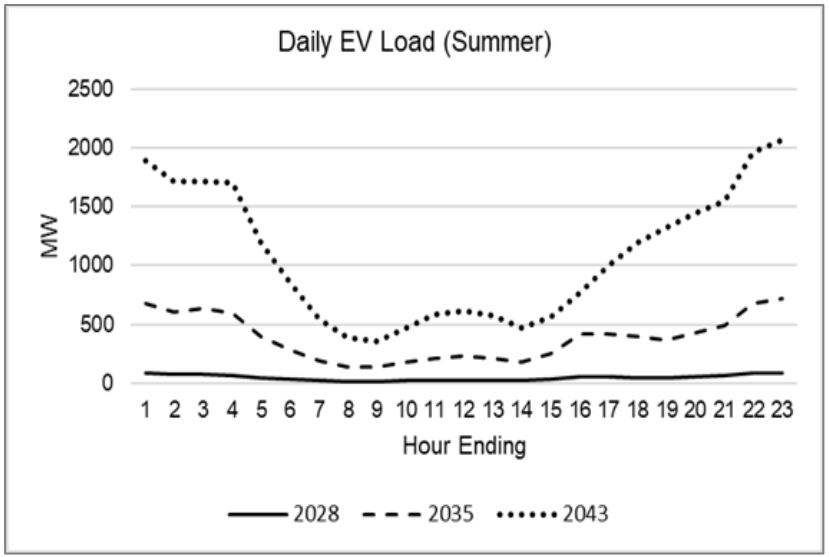




Charging Behaviour will Affect EV loads

- Charging behaviour will play an important role in managing the pronounced nature of EV loads
- EV charging presents potential for demand flexibility but may not be plausible across all vehicle categories.
  - AESO modelling assumes managed charging profiles for LDVs and MDVs.
- The AESO will continue to monitor EV load management activities by the DFOs.
- Compared to 2022, peak load is expected to increase by about 3.8 GW by 2043; if EV charging isn't managed, peak load could be an additional 0.3 GW by 2043.





* Daily charge includes 12% of losses

Hydrogen Production will Increase Industrial Load

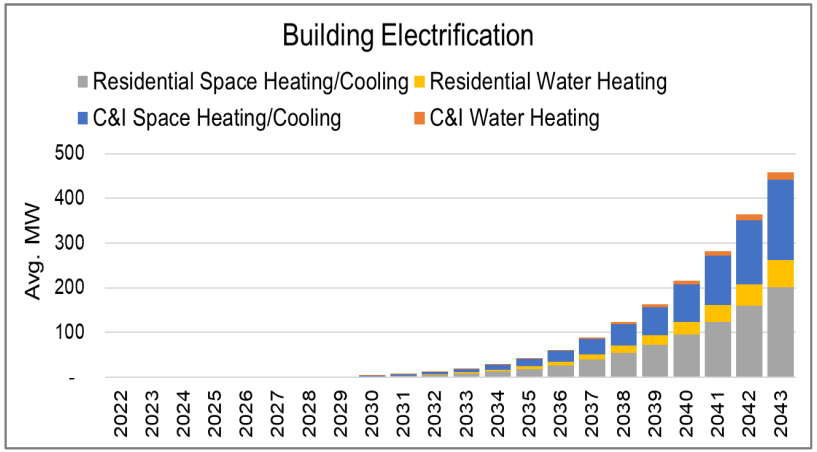
- Hydrogen produced in Alberta is assumed to be used in multiple industrial processes, but not other sectors
  - Hydrogen consumption in the transportation sector is explored as part of High Electrification scenario
- Methane reforming with carbon capture and sequestration (CCS) will gain significant market share in hydrogen production, especially in ammonia and methanol production
- Both autothermal reforming (ATR) and steam methane reforming (SMR) processes consume natural gas, water, and electricity as part of their processes

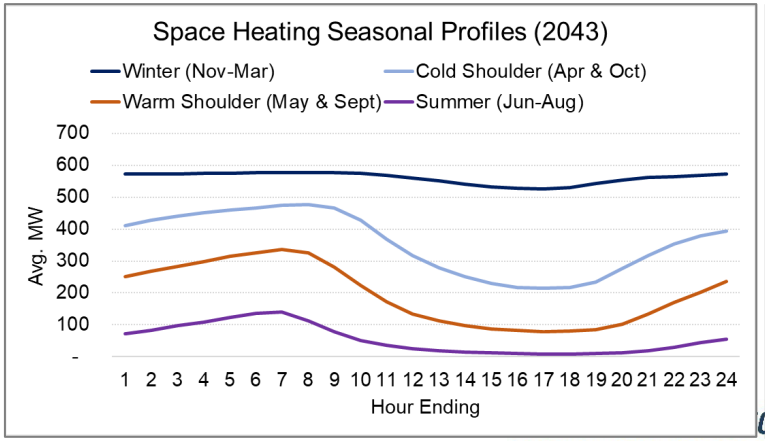
Technology Type	KWh/Kg
Electrolysis	Not Considered
SMR-CCS	2.0
ATR-CCS	4.0

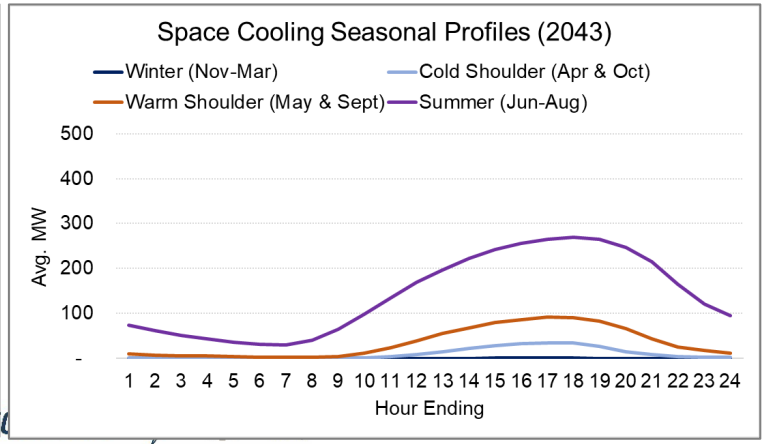
- Total CCS-based production will reach 1.2 million metric tonnes (MT) by 2030. Our hydrogen outlook includes new projects and assumptions about their timing and size.
- On average, production of 100,000 tonnes of hydrogen is estimated to consume 360 GWh of electricity (~40 MW on average)

Building electrification is not expected to be a major driver in the near term

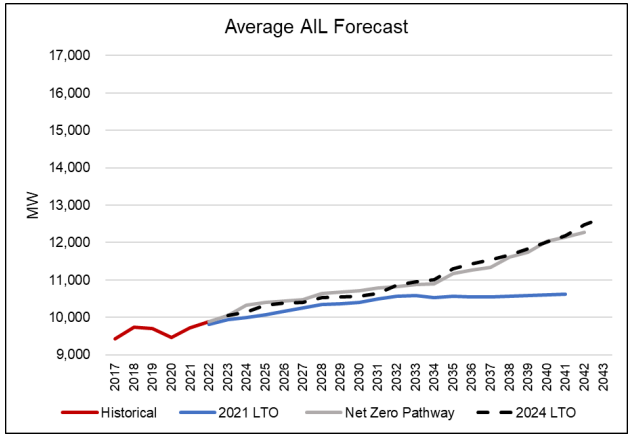
- Federal policy intentions to decarbonize the buildings sector by 2050 means majority of natural gas-based heating systems in Alberta will likely switch over to heat pumps and electric water tanks
  - Given the lack of policy specifics and/or incentives, electrification is expected to begin in new building constructions and retrofits from 2030 onwards
  - Advancements in hydrogen blending present a downside risk to these projections
- Increased building electrification is expected to add to weather-driven peaks, seasonality and intra-day variability

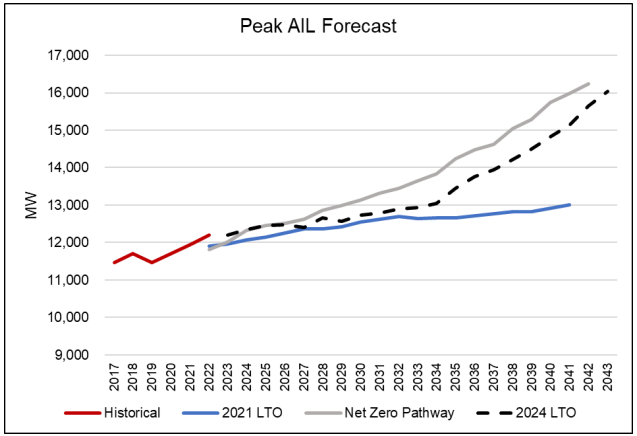


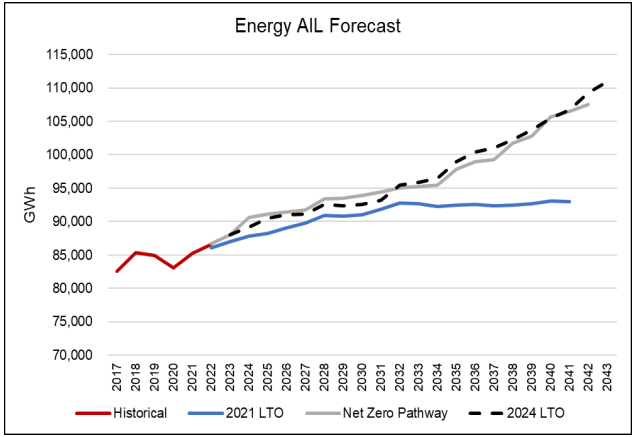




Reference case forecast growth is expected to depart from historical trends







- Energy consumption is expected to increase by approximately 28% (~ 24 TWh) in 2043 compared to 2022
- Peak load is expected to increase by about 32% (~ 3,850 MW) in 2043 compared to 2022

Twenty-Year Compound Annual Growth Rate	Historical (2003-2022)	2024 LTO (Reference Case) (2024-2043)	Net Zero Pathway (2023-2042)	2021 LTO (2022-2041)
Peak Growth (%)	1.7	1.4	1.6	0.5
Energy Growth (%)	1.7	1.2	1.1	0.4
Ratio (Peak: Energy)	1.0	1.2	1.5	1.2

- New forecast indicates that peak growth will surpass energy growth, demonstrating a slight shift from primarily baseload (industrial) loads to more variable loads with daily fluctuations

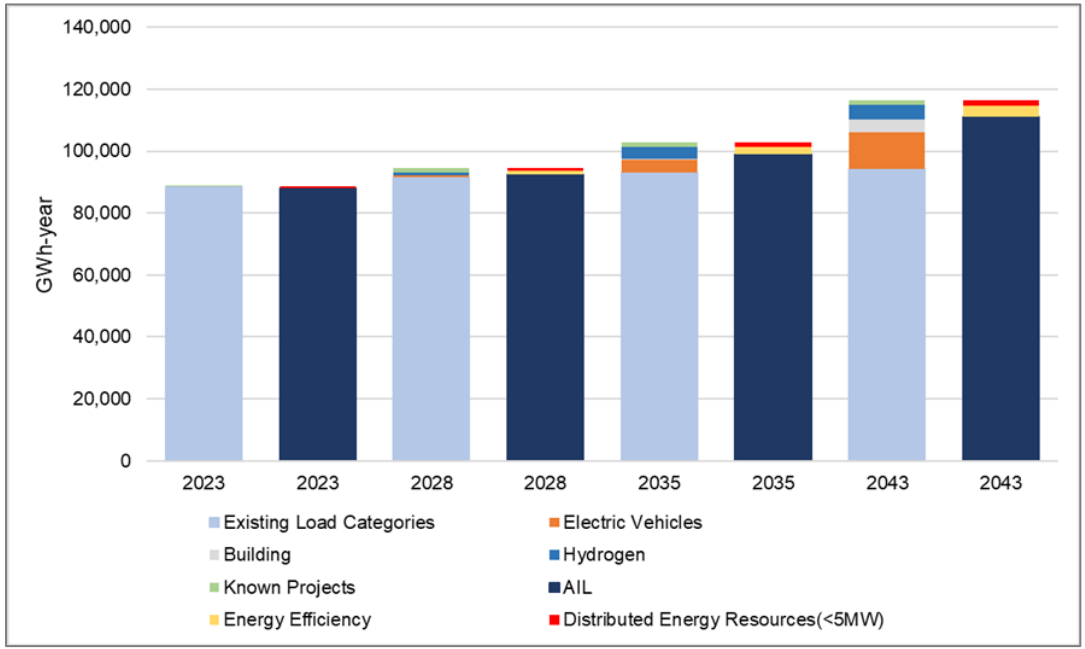
Impact of energy factors and traditional drivers of AIL

- AIL energy growth is expected to be 1.2% between 2024 and 2043

Contributions to AIL

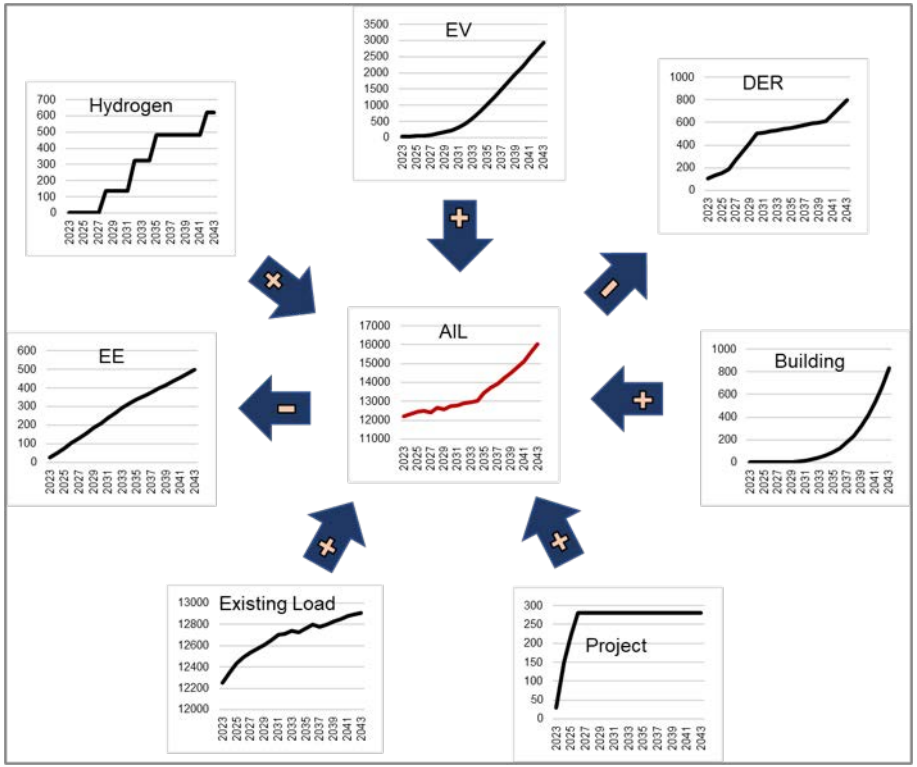
	2028	2035	2043
Existing Load	+99.0%	+94.0%	+85.0%
Known Projects	+1.6%	+1.5%	+1.3%
EVs*	+0.6%	+4.2%	+10.7%
Hydrogen	+1.2%	+3.8%	+4.4%
Building	+0.0%	+0.4%	+3.6%
EE*	-1.2%	-2.5%	-3.2%
DERs*	-1.1%	-1.4%	-1.7%

*EVs= Electric Vehicles
*EE= Energy Efficiency
*DERs= Distributed Energy Resources



AIL=Existing Load+ EVs*+ Hydrogen+ Known Projects+ Building- EE*- DERs*

Reference Case peak load growth is increasingly driven by electrification policy

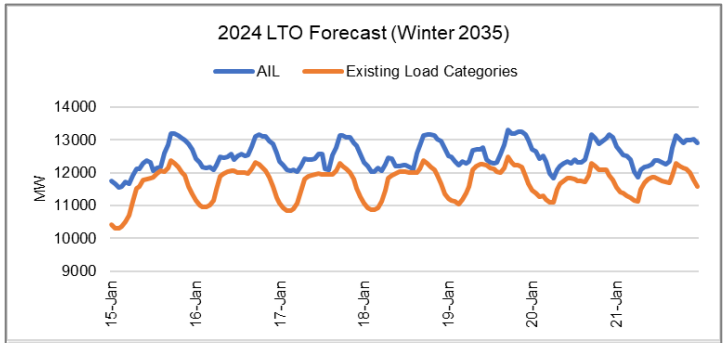


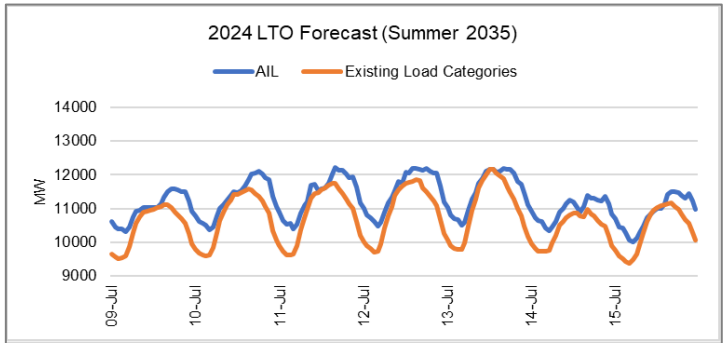
- The magnitude that each load modifier has on peak AIL varies
  - Yet the main factor driving the increasing trend in AIL peak growth is EVs particularly in the early 2030s with buildings not falling behind in the early 2040s

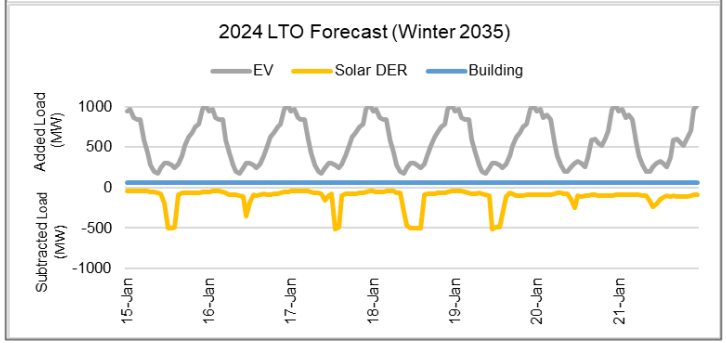
AIL=Existing Load+ EVs*+ Hydrogen+ Known Projects+ Building - EE*- DERs*

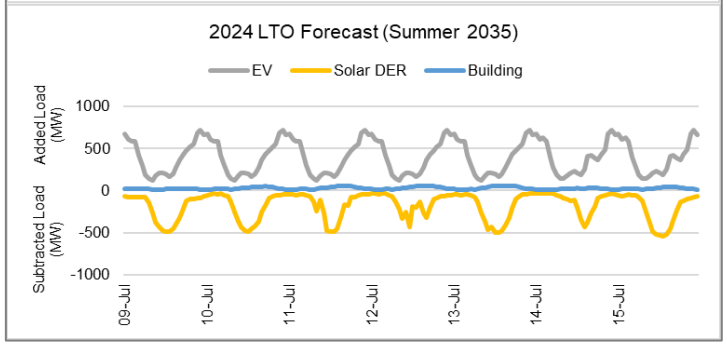
*EVs= Electric Vehicles
*EE= Energy Efficiency
*DERs= Distributed Energy Resources

AIL variability expected to increase due to non-industrial drivers of growth









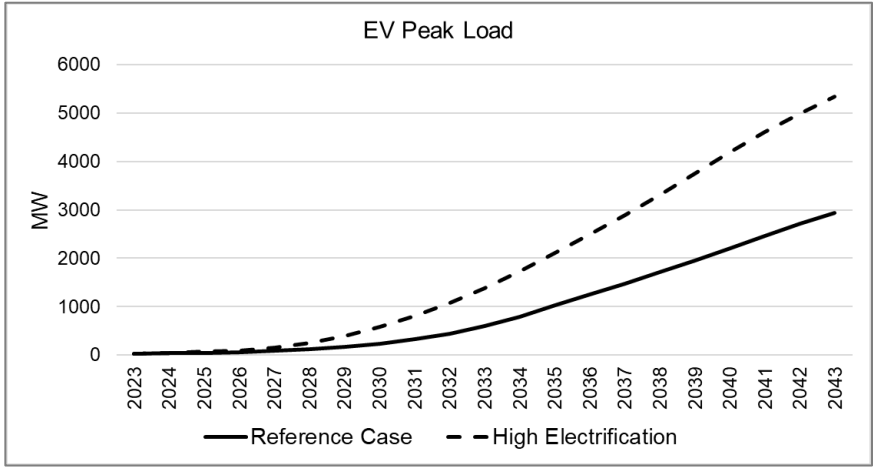
- Whereas industrial loads are typically stable and predictable with limited seasonality, new technologies accelerated by the energy transformation will introduce additional elements of day-to-day and intra-hour variability due to the aggregation of multiple consumer behaviours and constant adjustments to local weather impacts

High Electrification Scenario

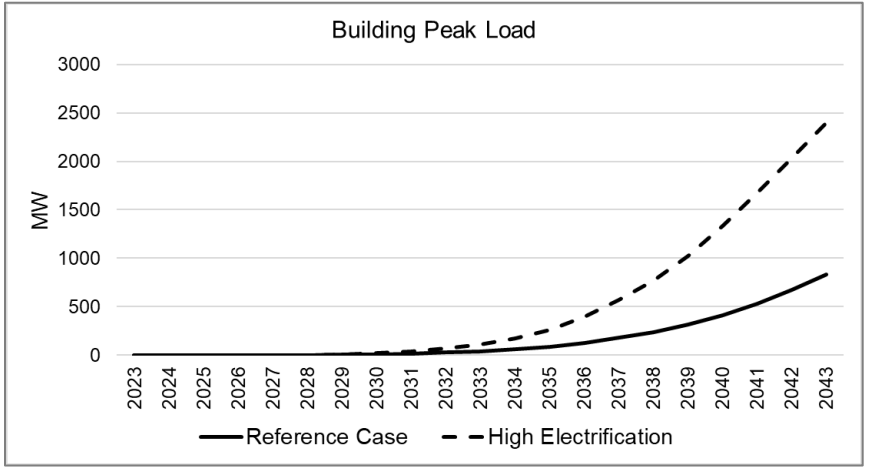
- Purpose:
  - The High Electrification scenario represents a greater pace and scale of electrification to achieve the decarbonization of different sectors
  - This scenario serves to capture upside risks and quantify a high boundary case for Alberta
  - It maintains most assumptions from the Reference Case but represents more aggressive adoption of EVs and heat pumps as well as additional electrification in heavy industries

High Electrification focuses on increased and accelerated EV and heat pump adoption

- In both the Reference Case and High Electrification scenarios, the peak load attributed to electric vehicles is expected to reach 2,941 MW and 5,345 MW, respectively, which demonstrates a remarkable increase in electric vehicle adoption

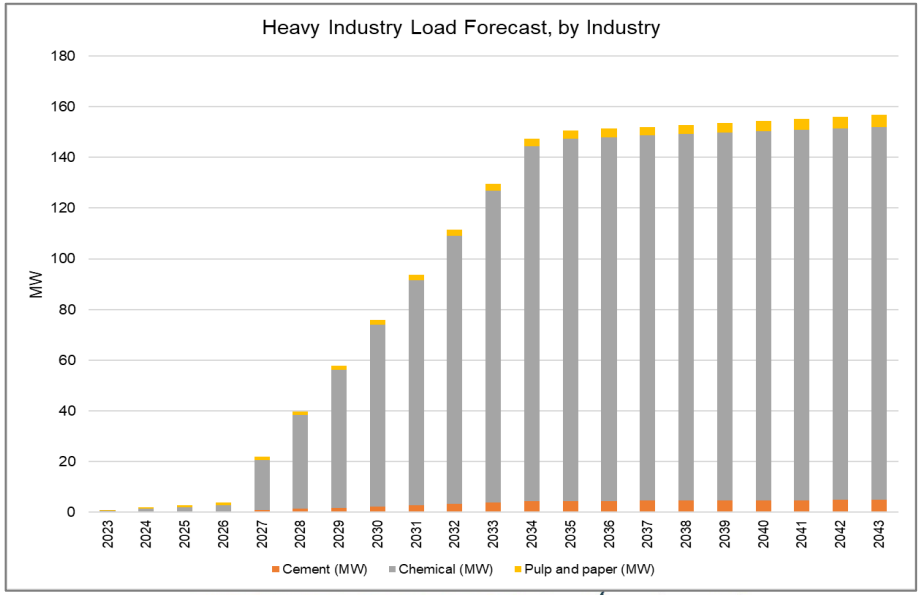


- In both the Reference Case and High Electrification scenarios, we observe a significant increase in adoption rates for building electrification, with the peak load projected to reach 833 MW and 2,400 MW by 2043, respectively

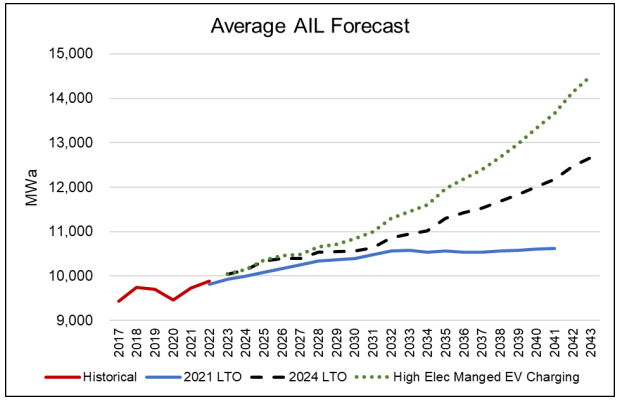


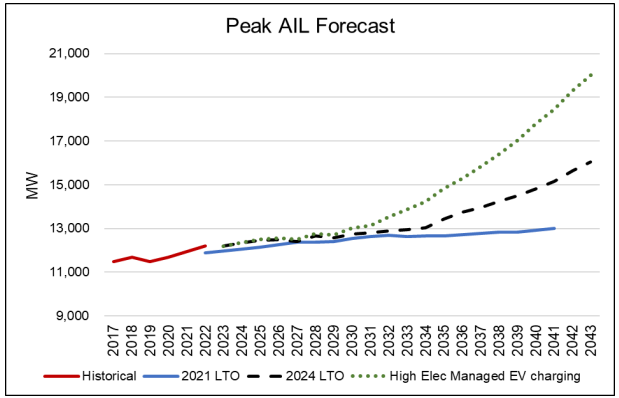
High Electrification includes impact from the electrification of Alberta's heavy industries

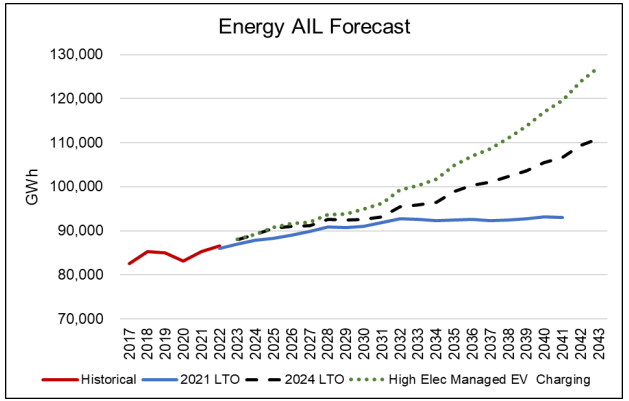
- Heavy industry electrification assumptions are largely based on the federal emissions reduction plan
  - AESO focuses highest-emitting sectors such as chemical, cement, and pulp and paper industries
  - Gradual carbon capture and storage uptake for chemical and cement industries starts in 2027



Forecast growth is expected to depart from historical trends







- Energy consumption is expected to increase by approximately 47% (~ 40 TWh) in 2043 compared to 2022 in the High Electrification scenario
- In 2043, we expect a significant increase in peak load, with projections indicating a rise of 64% increase (~ 7,800 MW) in the High Electrification scenario when compared to the levels recorded in 2022.

Twenty-Year Compound Annual Growth Rate	Historical (2003-2022)	2024 LTO (Reference Case) (2024-2043)	2024 LTO (High Electrification) (2024-2043)
Peak Growth (%)	1.7	1.4	2.6
Energy Growth (%)	1.7	1.2	1.9
Ratio (Peak: Energy)	1.0	1.2	1.4

Uncertainty and sensitivities around the load forecast

- Load growth uncertainty is largely based on multi-policy outcome uncertainty, technological deployment pace and magnitude, among other things
  - Impact to long-term outlook can be significant, raising the importance of studying key sensitivity cases
  - The AESO continues to monitor key signposts to calibrate and refine forward views of these load drivers

	Policy	Technology	Other
GDP and Oilsands	• O&G emissions cap • Energy security	• Pipeline expansions and electrification	• Demographics • Global / continental trade
DER and Energy Efficiency	• Government incentives for microgeneration and retrofits	• Capital cost declines • DSM and load aggregators	• Power prices
EVs	• Zero-emissions vehicle sales mandate • Government incentives	• Supply availability and suitability • Active management technology • Vehicle-to-grid integration	• Consumer behaviour • Adoption by class (LDV, MHDV, buses)
Buildings	• “Net-Zero” building code (Canada Green Buildings Strategy) • Carbon pricing impact on NG	• Cold-climate heat pump advancements • High % hydrogen blending	• Consumer behaviour and acceptance
Industrial	• Government support for hydrogen and CCS projects • Carbon price and emissions benchmark uncertainty	• Advancement in hydrogen production and delivery • CCS advancement beyond power generation (i.e., heavy industries)	• Regulatory and market treatment of cogeneration and net-exports to the grid

2024 LTO Reference Case – Preliminary Generation Outlook

Regulatory Assumptions Update

2024 LTO scope has expanded to model two distinct regulatory scenarios

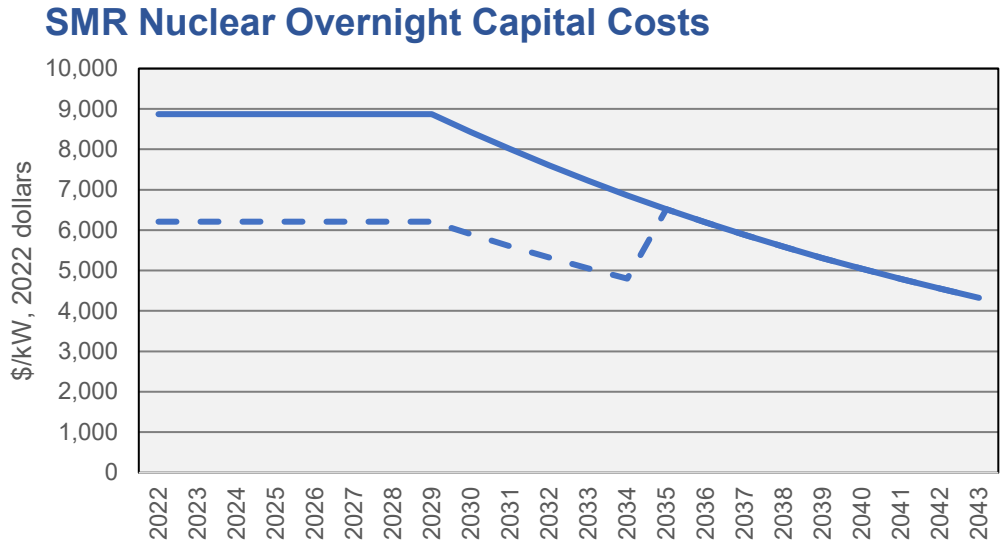
Decarbonization by 2050 Scenario

- Does not include federal Clean Electricity Regulation restrictions
- TIER electricity high performance benchmark declines linearly from 2030 to zero in 2050

Decarbonization by 2035 Scenario

- Includes federal Clean Electricity Regulation restrictions
- TIER electricity high performance benchmark declines linearly from 2030 to zero in 2035

Key Generation Cost Assumptions Update



- Both 2035 and 2050 Decarbonization scenarios assume Nuclear Small Modular Reactors (SMR) capital costs decline 5% per year between 2030 and 2050
- Cost estimate based on next-of-a-kind estimates from 2019 Status Report for BWRX-300[1]

1 Status Report – BWRX-300

2024 LTO Generation Forecast – Key Messages

- Development of supply technologies in the 2024 LTO is heavily influenced by federal investment tax credit (ITC) subsidies, increasing carbon tax rates, tightening high-performance benchmarks, and *Clean Electricity Regulations* (CER)
- The 2024 LTO Reference Case forecast anticipates significant renewable development in the 2020's and early 2030's driven by corporate PPA interest, 30% reduced capital costs from the federal investment tax credits, and forecast technological capital cost declines
  - The pace of renewable development is expected to accelerate compared to previous AESO forecasts
- Carbon capture retrofits of existing combined-cycle assets are viewed as cost-effective thermal technology in the 2020's due to the reduced carbon price exposure, while receiving 50% subsidization of carbon capture technology costs via refundable federal investment tax credits
- Least efficient gas assets are forecast to retire or mothball in the near term due to increased competition from new combined-cycle and cogeneration assets
- Energy storage experiences growth in niche ancillary service applications, but is not expected to be cost effective for energy arbitrage given forecast costs

Key Generation Assumptions

- Generation forecast is predicated on the existing market framework
  - New build forecast follows economic build, based on a 10.5% pre-tax Weighted Average Cost of Capital (WACC)
  - Model assumes a congestion free transmission system
- Wind, solar, and battery energy storage and nuclear capital costs are expected to decline towards 2030
- Combined-cycle natural gas with carbon capture, utilization, and storage (CCUS), nuclear SMR and hydrogen-fired technologies represent key decarbonization technologies in the 2024 LTO
- Hydro-electric technologies, and storage technologies have been included as future decarbonization opportunities

Key Regulatory Assumptions

- The Government of Canada launched various tax credits in their *Budget 2022*, *Fall Economic Statement 2022* and *Budget 2023* documents including:
  - *Clean Technology Investment Tax Credit*
    - Refundable credits of up to 30% of capital cost for eligible projects including wind, solar, energy storage, nuclear (SMR), geothermal, small/renewable hydro and other clean projects (available until 2035)
  - *Clean Electricity Investment Tax Credit*
    - Enhances the *Clean Technology Investment Tax Credit* and makes it available to non-taxable entities at a refundable rate of 15%
    - Adds abated natural gas-fired electricity generation, large scale hydro, and large scale nuclear
    - Adds 15% refundable tax credit for interprovincial transmission
  - *Clean Electricity Focus for the Canada Infrastructure Bank (CIB)*
    - Enable low-cost financing for renewable energy, energy storage, and transmission projects
    - Support electrification and affordability with $20 billion of financing for clean electricity and clean growth infrastructure projects
- These subsidies could intensify a flurry of renewable development, and were expected as a Canadian federal response to the USA's *Inflation Reduction Act*
- Investment Tax Credits have the potential to incentivize significant generation capacity

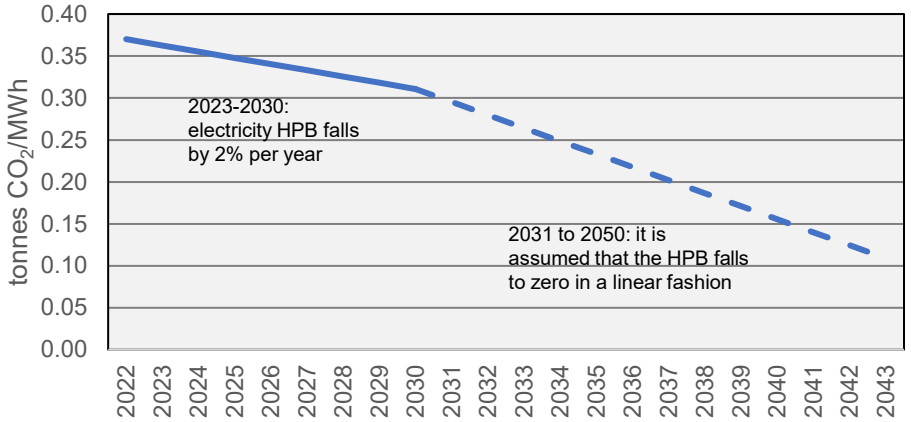
Key Regulatory Assumptions (con't)

- *Clean Electricity Regulations for Decarbonization by 2035 scenario*
  - 5% capacity factor limit on unabated gas assets post 2035
  - 20-year end of prescribed life on thermal assets which allows a limited number of thermal assets to operate above a 5% capacity factor post 2035
  - Units below 25 MW would be exempt from the clean electricity regulation
  - No adjustments were made to cogeneration based on the CER
    - Impact to Cogeneration to be included in new modelling in 2024
    - Installation of carbon capture at cogeneration sites could reduce net-to-grid generation by ~500 MW and would require additional new base load generation for the grid
  - Assumptions will be reviewed when CER is published in the *Canada Gazette I*
- *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*
  - Assumed all coal-to-gas units must retire by 2037, at the latest, based on the end-of-life extensions under the federal coal regulations utilized for both scenarios
- *Greenhouse Gas Pollution Pricing Act*
  - Federal regulation is expected to continue to impose a carbon tax on industrial emissions in Alberta and is consistent across scenarios

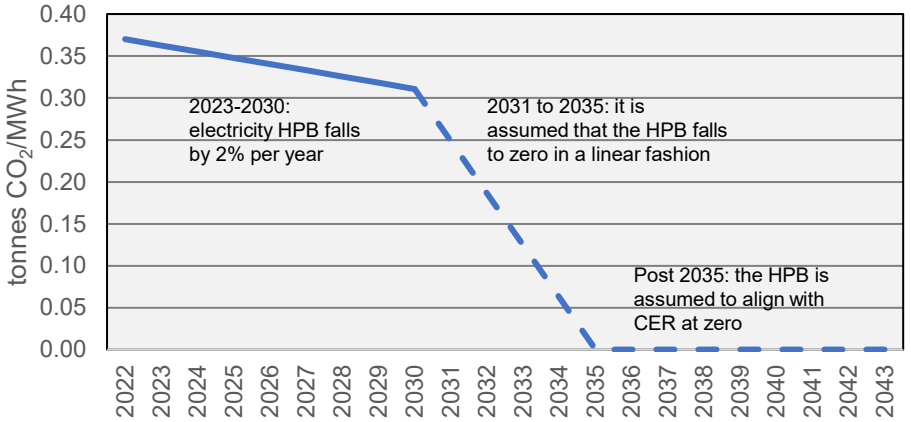
Provincial Carbon Regulation Assumptions

TIER Electricity High Performance Benchmarks

Decarbonization by 2050



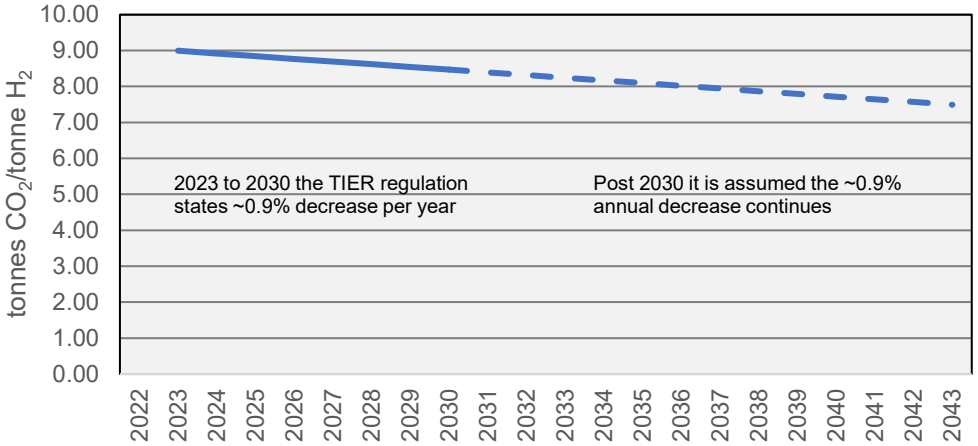
Decarbonization by 2035



- TIER benchmarks have been published to 2030 and are reflected in the 2024 LTO reference case
- Carbon price increases by $15 per annum to $170 per tonne by 2030, per December 2022 Ministerial Order 62/2022
  - AESO assumes inflationary escalation thereafter
- Assumptions post 2030 have been made that align with federal CER for the 2035 scenario, and aligned with expected provincial target of 2050 for the 2050 scenario
  - Emitting technologies will have increasing exposure to increasing carbon prices in both scenarios
  - Renewables realize higher emissions performance credits in 2050 scenario relative to 2035 scenario

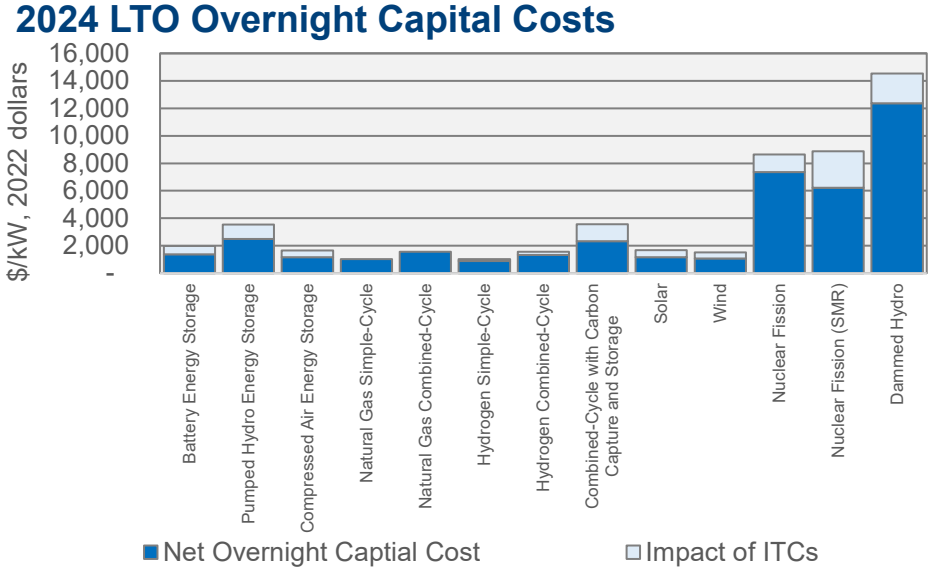
Provincial Carbon Regulation Assumptions

TIER Hydrogen High Performance Benchmark



- Hydrogen High Performance Benchmark utilized in both 2035 and 2050 Decarbonization scenarios
- December 2022 TIER regulation update requires that hydrogen fired electricity generators that import fuel pay a ‘true-up’ carbon compliance cost (previously the Allowable Emissions level couldn’t be negative)
  - Ensures fair treatment and impacts the cost of hydrogen for the purpose of electricity generation
  - Reduces the hydrogen fired generation in the 2024 LTO Base Cases compared to the Net-Zero scenarios
- The linear decline in Hydrogen HPB translates to a lower cost of hydrogen production, but a higher true-up cost if used for electricity generation.

Key Generation Cost Assumptions



- Wind and solar have the lowest capital cost of low emission technologies with further decreases from the federal ITC ($1,563/kW and $1,687/KW before 30% ITC, respectively)
- Combined-cycle with CCS experiences significant subsidization:
  - 50% *ITC for Carbon Capture, Utilization, and Storage* on the emissions control investment
  - 15% decrease from the *Clean Electricity ITC* on the abated natural gas power plant investment

Pace and Magnitude of Renewable Development

Increase

- Robust wind/solar resource potential
- Corporate PPAs help achieve ESG goals (not dependent solely upon power prices)
- Increased Federal government support (i.e., Investment Tax Credits)
- Ease of entrance into Alberta market
- Investor interest exhibited via project list

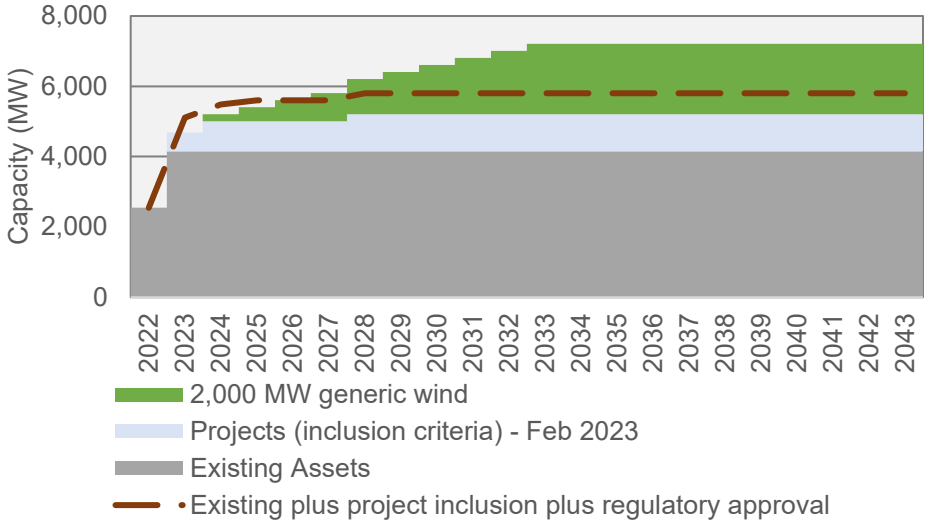
Decrease

- Localized congestion for renewables occurring given concentrated siting opportunities
- Financing and material costs have increased recently
- Regulatory uncertainty (e.g., continued changes to TIER, CER development, carbon pricing post 2030)
- Land use considerations

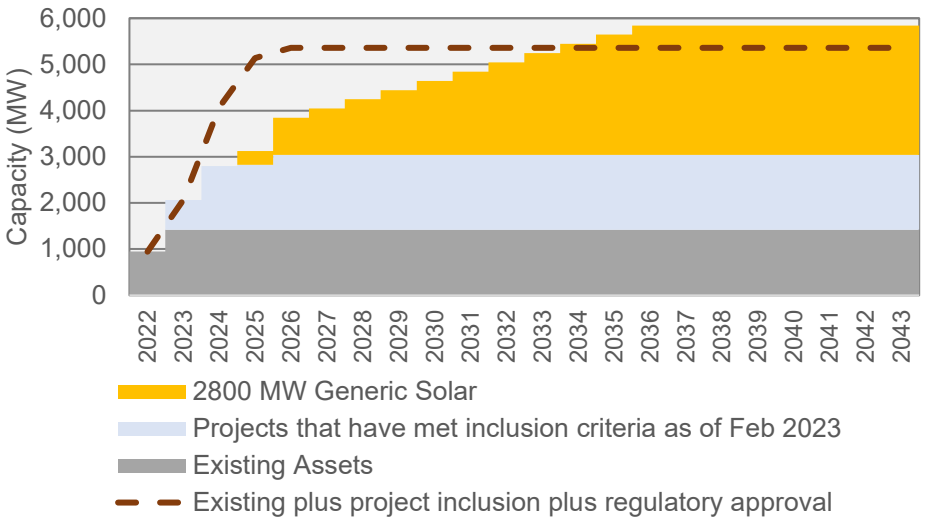
- Although there is uncertainty regarding renewable development trends, continued growth seems likely
- Forecasting & Analytics has developed a multifaceted approach to forecasting renewable generation additions, incorporating insights from:
  - Corporate ESG reports from Canadian and multi-national corporations
  - The AESO's Project List and inclusion criteria
  - Project and Market economic assessments
- AESO will continue to track the pace and drivers of renewable development in the province

2024 LTO Reference Case Renewable Generation Forecast

2024 LTO Reference Case Wind Forecast

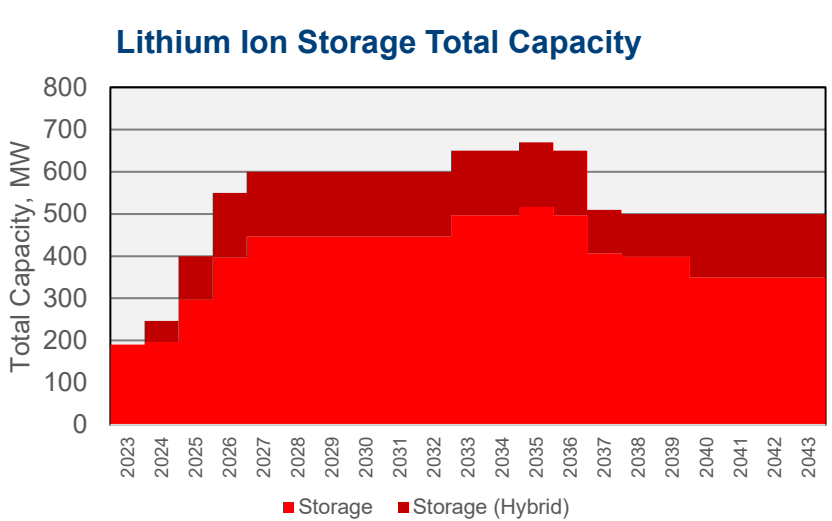


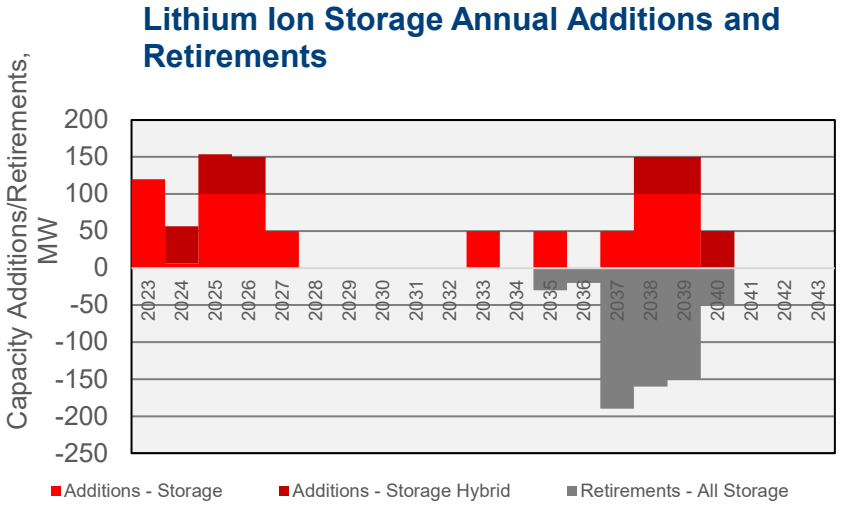
2024 LTO Reference Case Solar Forecast



- Current project list exhibits increased interest in solar compared to wind
- Corporate PPA interest is expected to remain strong, based on surveyed ESG reports from Canada's top 300 firms by market capitalization and top 50 US multinational corporations
- Capture price for renewables is expected to decline with higher concentrations of correlated resources, impacting wind more than solar
- These factors informed a renewable forecast of 2,000 MW of incremental wind and 2,800 MW of incremental solar (additional to projects that have met the AESOs inclusion criteria)
  - Incremental wind and solar decreased compared to June 2023 presentation due MW shifting into "existing assets"

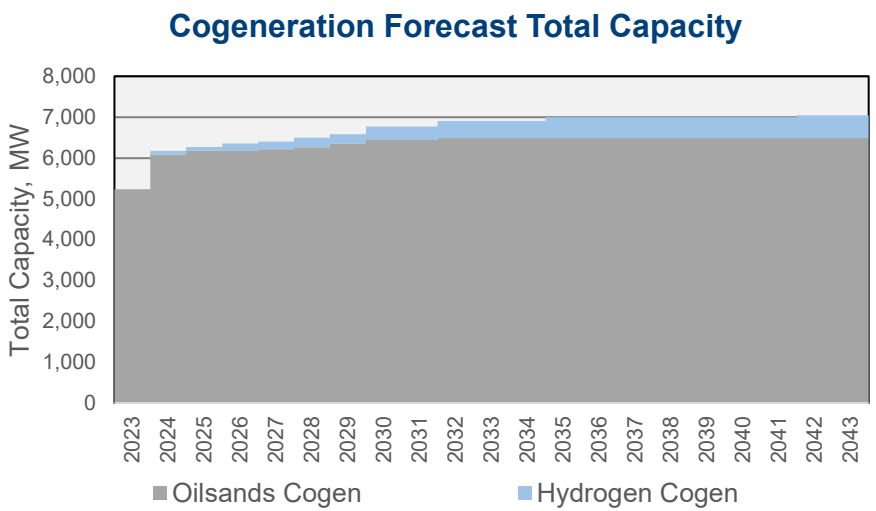
Storage Forecast

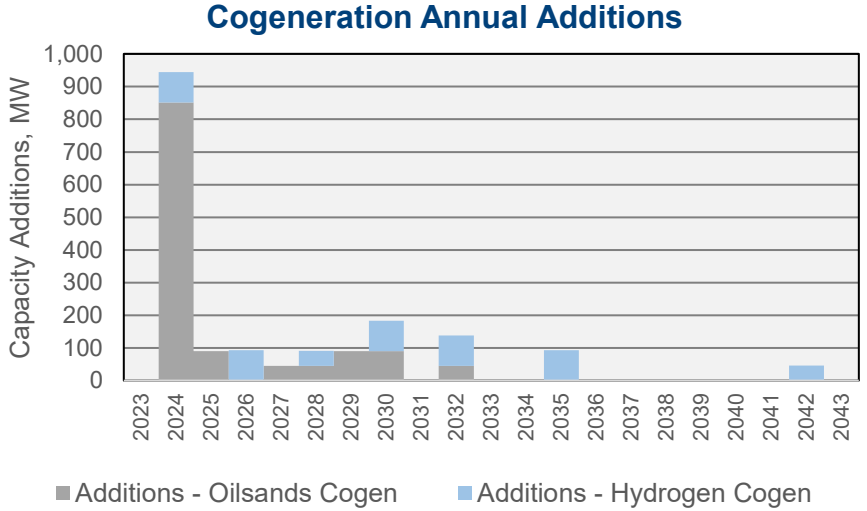




- Storage forecast largely driven by participation in ancillary service markets
  - Lithium-ion storage assumed to be replaced at 14-year intervals
- Economic modelling does not support storage development for the exclusive purpose of energy arbitrage in the existing market framework with forecast capital costs for storage

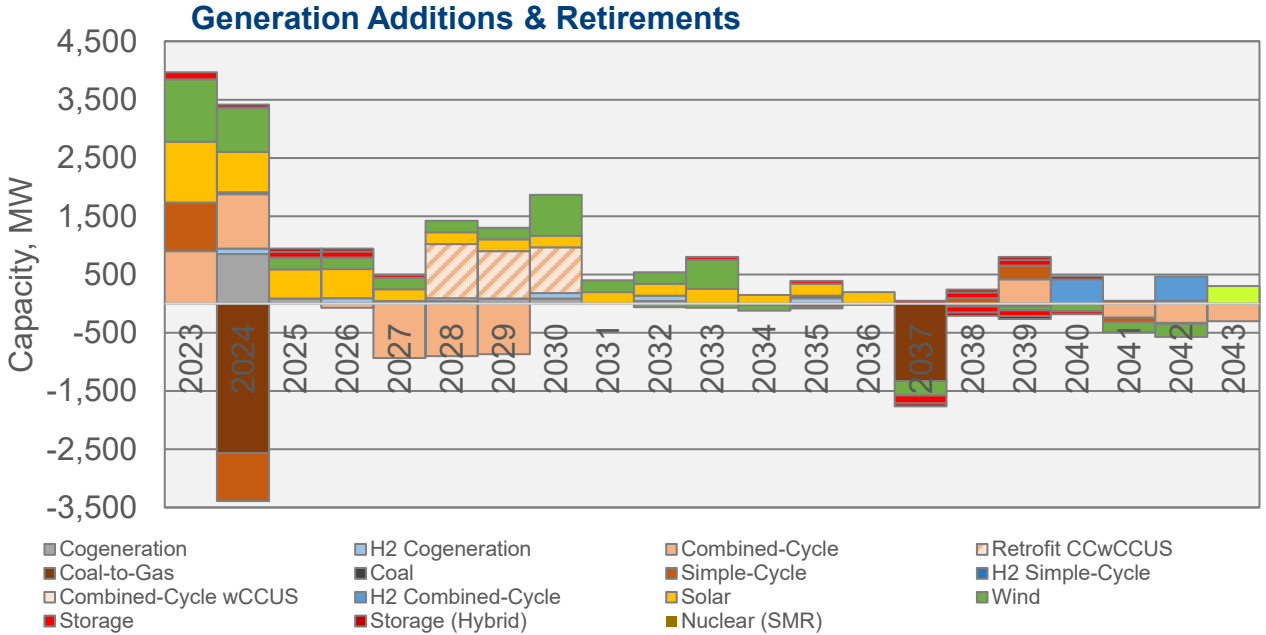
Cogeneration Forecast





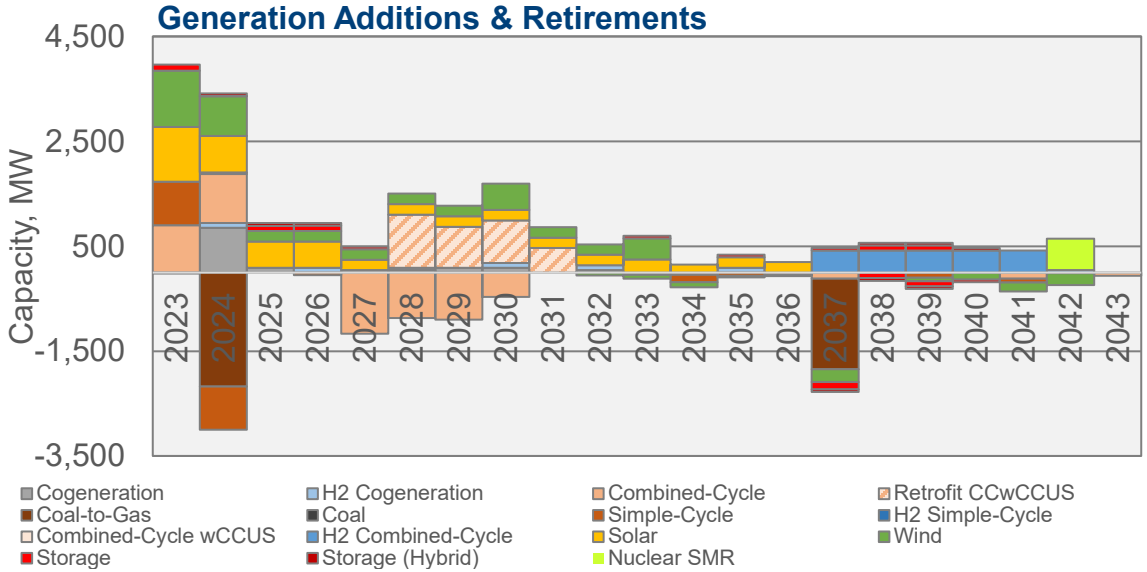
- Oilsands cogeneration forecast is aligned with the load forecast, insights from IHS Markit, and the expectation of no new greenfield oilsands projects going forward within the forecast horizon
- Hydrogen cogeneration forecast developed in tandem with hydrogen production load forecast
  - Assumes that electricity production of the cogeneration would meet approximately half of the electrical load

Generation Additions and Retirements – 2050



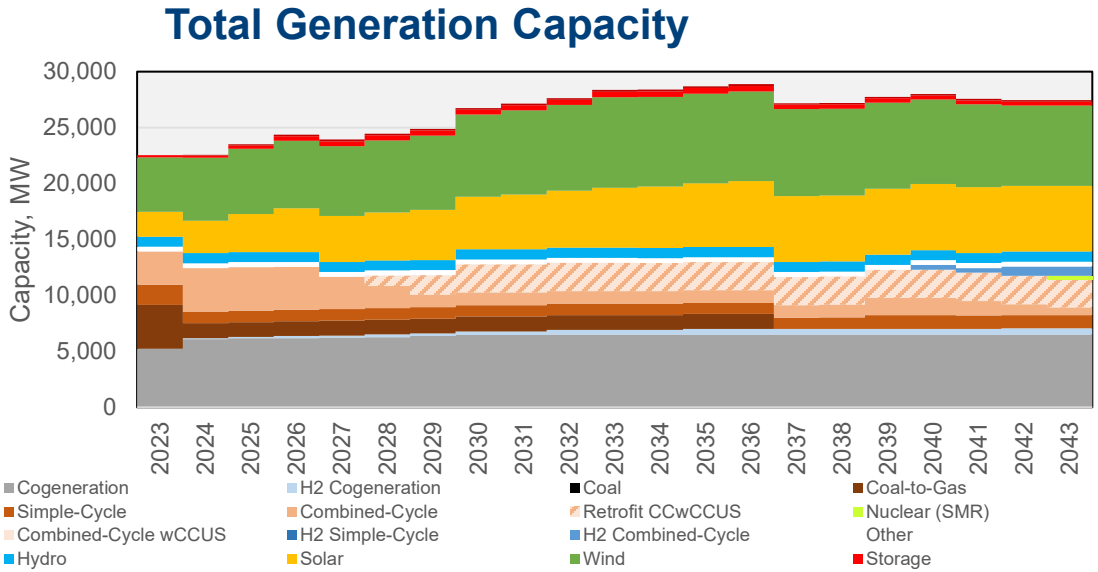
- 2,800 MW of combined-cycle with CCUS retrofits forecast in the late 2020's to early 2030's reduces emissions significantly and slightly decreases overall capacity of assets
- Strong wind and solar additions in the near-term taper towards the mid 2030's, with 300 MW additional wind built compared to 2035 scenario
- Hydrogen, unabated combined-cycle and simple-cycle assets expected to enter in late 2030's to replace coal-to-gas asset retirements resulting from the federal coal regulations, carbon tax, and the *Clean Electricity Regulations*
- Significant generation additions in 2023 and 2024 drive retirement/mothball of least efficient thermal generation
- Nuclear developments towards the end of the forecast period resulting from assumed cost declines

Generation Additions and Retirements – 2035



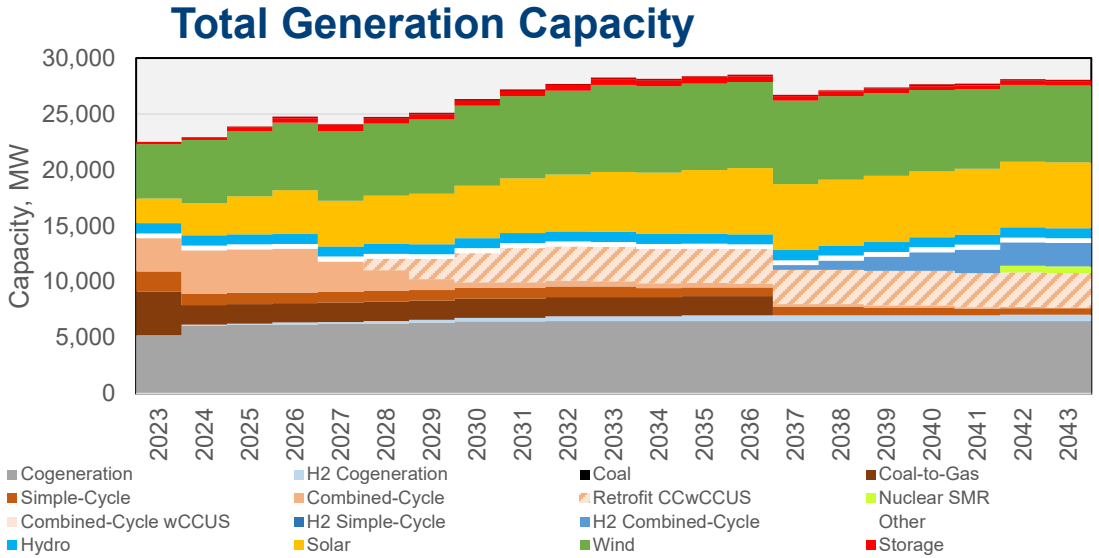
- 3,070 MW of combined-cycle with CCUS retrofits forecast in the late 2020's to early 2030's reduces emissions significantly and slightly decreases overall capacity of assets
- Strong wind and solar additions in the near-term taper towards the mid 2030's
- New hydrogen assets expected to enter in late 2030's to replace coal-to-gas asset retirements resulting from the federal coal regulations, carbon tax, and the *Clean Electricity Regulations*
- Significant generation additions in 2023 and 2024 drive retirement/mothball of least efficient thermal generation
- Nuclear developments towards the end of the forecast period resulting from assumed cost declines

Generation Capacity Forecast – 2050



- Wind, solar, and combined-cycle with CCUS are the dominant development technologies in the forecast:
  - 7,300 MW of wind capacity
  - 6,000 MW of solar capacity by early 2030's
  - 2,500 MW of existing combined-cycle retrofit with CCUS
- 450 MW of storage additions in the 2020's related to operating reserves and Fast Frequency Response (FFR) procurements
- 558 MW of hydrogen cogeneration additions related to hydrogen production facilities
- 1,200 MW of cogeneration additions (850 MW representing the Suncor boiler replacement project)

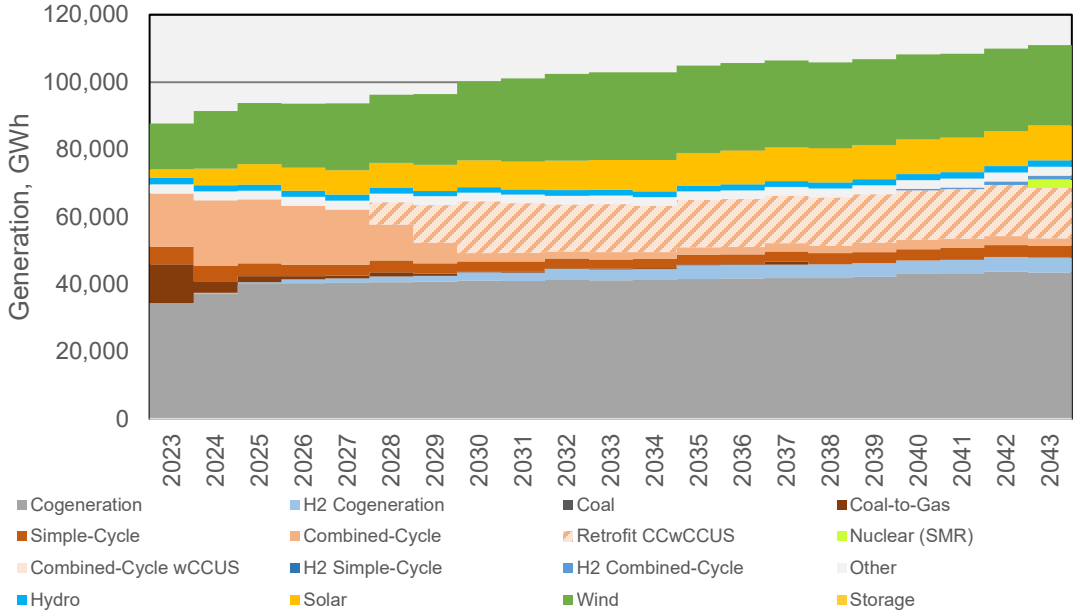
Generation Capacity Forecast - 2035



- Wind, solar, and combined-cycle with CCUS are the dominant development technologies in the forecast:
  - 7,800 MW of wind capacity
  - 6,000 MW of solar capacity by late 2030's
  - 3,074 MW of existing combined-cycle retrofit with CCUS
- 450 MW of storage additions in the 2020's related to operating reserves and Fast Frequency Response (FFR) procurements
- 558 MW of hydrogen cogeneration additions related to hydrogen production facilities
- 1,200 MW of cogeneration additions (850 MW representing the Suncor boiler replacement project)

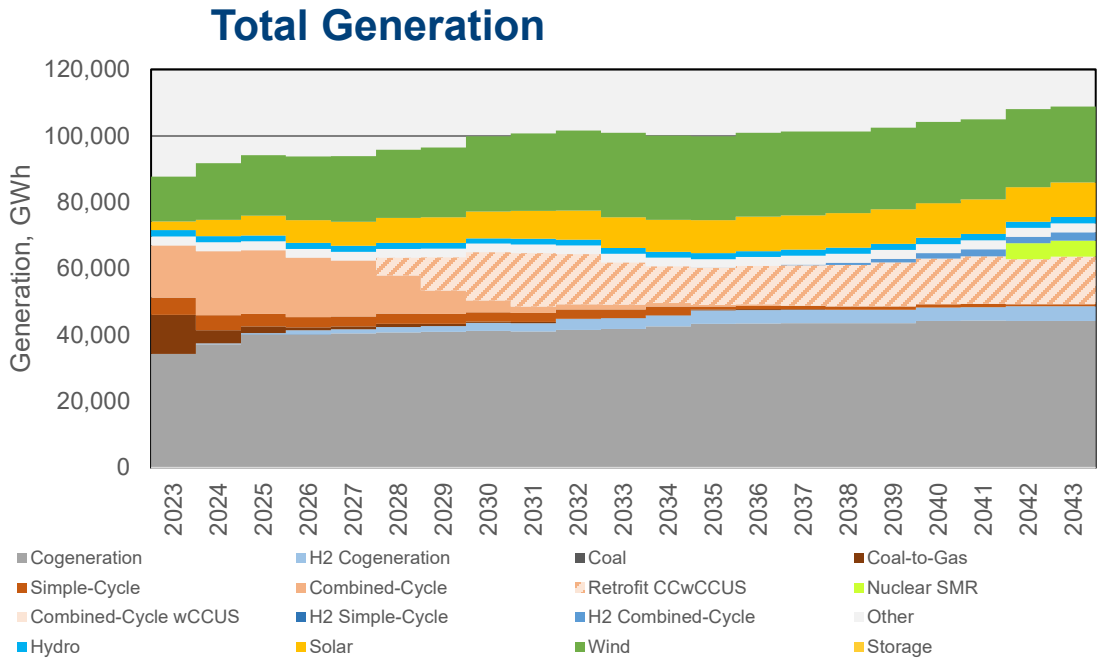
Generation Energy Forecast – 2050

Total Generation



- Renewable energy reaches 33% of generation by 2030 and peaks at 36% in 2033
- Combined-cycle with CCUS retrofits contribute significantly to generation, reaching 15% of energy in 2030
- Peaking capacity (natural gas simple-cycle and combined-cycle, hydrogen simple-cycle and combined-cycle, coal-to-gas assets) makes up a small portion of total energy despite no *Clean Electricity Regulations* in effect

Generation Energy Forecast – 2035



- Renewable energy reaches 32% of generation by 2030 and peaks at 37% in 2034
- Combined-cycle with CCUS retrofits contribute significantly to generation, reaching 16% of energy in 2031
- Peaking capacity (natural gas simple-cycle and combined-cycle, hydrogen simple-cycle and combined-cycle, coal-to-gas assets) makes up a small portion of total energy post 2035 with the *Clean Electricity Regulations* in effect

Generation Capacity Scenario Comparison

	Decarbonization by 2050				Decarbonization by 2035			
	*2023	2028	2035	2043	*2023	2028	2035	2043
Combined-Cycle Natural Gas	2,966	1,993	1,125	973	2,966	1,861	411	61
Cogeneration Natural Gas	5,234	6,266	6,491	6,491	5,235	6,266	6,491	6,491
Coal-to-Gas Conversions	3,895	1,329	1,329	-	3,895	1,724	1,724	-
Cogeneration Hydrogen	-	233	512	558	-	233	512	558
Hydroelectric	894	894	894	894	894	894	894	894
Combined-Cycle Hydrogen	-	-	-	837	-	-	-	2,092
Simple-Cycle Hydrogen	-	-	-	-	-	-	-	-
Nuclear SMR	-	-	-	300	-	-	-	600
Other	444	444	444	444	444	444	444	444
Combined-Cycle CCUS Retrofit	-	932	2,525	2,525	-	1,015	3,074	3,074
Simple-Cycle Natural Gas	1,816	1,024	991	1,189	1,798	956	750	581
Solar	2,207	4,302	5,702	5,887	2,207	4,302	5,702	5,887
Storage	190	597	617	500	190	550	570	500
Wind	4883	6,439	8,011	7,169	4,883	6,439	7,711	6,869
Totals	**22,531**	**24,452**	**28,640**	**27,767**	**22,512**	**24,683**	**28,283**	**28,051**

*Note 2023 values include existing and anticipated project capacity as of the Apr 2023 connection project list

Previous Forecast Generation Capacity

	Preliminary LTO (June 8th session)				Net Zero First Mover Advantage	Net Zero Renewable and Storage Rush	2021 Clean-Tech Scenario	2021 LTO Reference Case
	*2023	2028	2035	2043	2035	2035	2035	2035
Combined Cycle Natural Gas	1,810	1,861	411	1,630	3,056	1,548	4,822	2,648
Cogeneration Natural Gas	5,235	6,266	6,491	6,491	6,712	6,712	6,669	6,669
Coal-to-Gas Conversions	3,075	1,724	1,724	-	929	-	935	2,535
Cogeneration Hydrogen	0	233	512	558	-	-	-	-
Hydroelectric	894	894	894	894	894	894	894	894
Combined-Cycle Hydrogen	-	-	-	837	-	-	-	-
Simple-Cycle Hydrogen	-	-	-	698	1,599	863	-	-
Other	444	444	444	444	443	443	473	423
Combined-Cycle CCUS Retrofit	-	745	2,804	2,804	-	-	-	-
Simple-Cycle Natural Gas	1,240	1,304	1,244	962	1,278	1,205	1,520	1,397
Solar	1,179	4,302	5,702	5,887	2,572	3,444	2,114	1,104
Storage	90	497	517	500	310	3656	1,200	120
Wind	3,618	6,439	7,211	6,369	6,922	8,722	4,797	4,717
Coal	820	-	-	-	-	-	-	-
Totals	**18,405**	**24,709**	**27,954**	**28,074**	**24,715**	**27,487**	**23,424**	**20,507**

*Note 2023 values include existing capacity as of June 2023 as publicly reported on the AESO Current Supply Demand Report

2024 LTO Generation Forecasting: Key Observations

- The generation landscape is expected to continue to change in Alberta
  - Decarbonization objectives and regulation drive low-emitting technologies
  - Time-sensitive Investment Tax Credits are forecast to drive technological investment decisions including renewable generation and carbon-capture technologies
- Significant volumes of high-efficiency combined-cycle, cogeneration, and intermittent renewable generation are forecast to commercialize in the next few years, which could moderate additional new builds until the 2030s
- Remaining coal-to-gas assets provide peaking value as electrification of transportation and heating exacerbate load growth in the late 2030's
  - New peaking technologies present investment challenges after the 2038 retirement of these legacy units, in consideration of federal regulations

Further Model Enhancements being explored

- Refine financial modelling on carbon reduction pathways for Cogeneration assets
  - Retrofit cogeneration with CCS, or install CCS on existing oilsands boilers
- Add ability for simulation to retrofit existing peaking facilities to utilize hydrogen
- Align recent project announcements with inclusion criteria and forecasted values

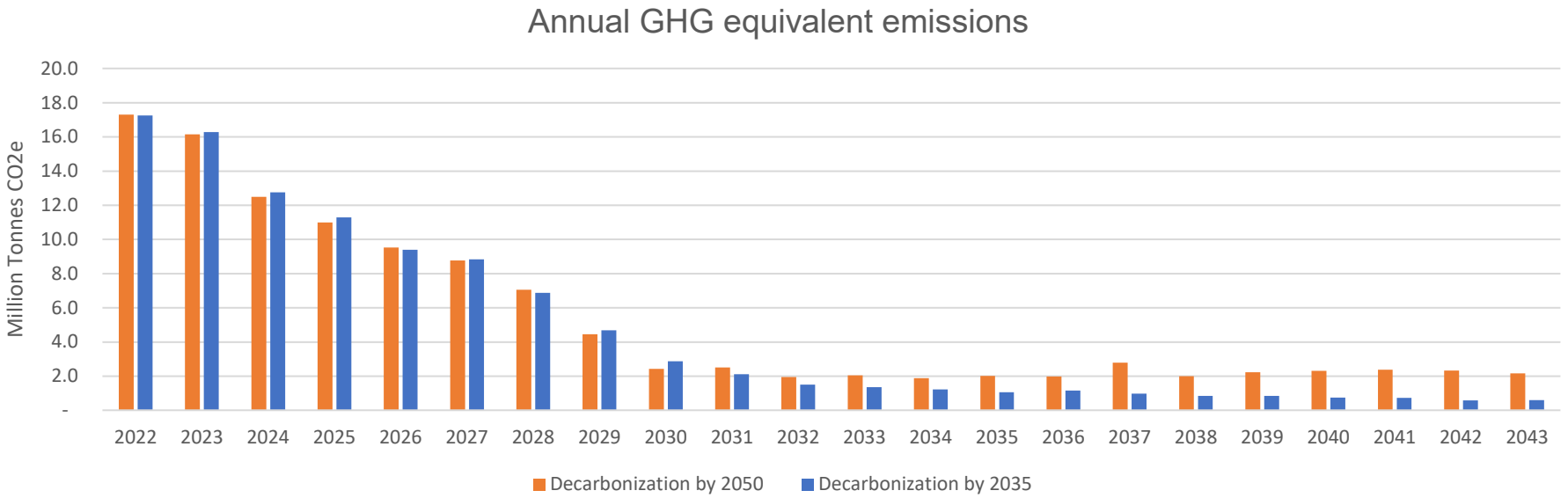
Preliminary Inputs, Insights and Outcomes

Public

Key Generation Cost and Performance Assumptions

Technology	Capacity, MW	Capital Cost, $2022/kW		Efficiency or Heat Rate, % or GJ/MWh	Fixed O&M, $2022/kW-yr	Variable O&M, $2022/MWh
		2022	2030			
Solar PV	50	1,687	1,323	-	27.05	-
Wind	100	1,563	1,385	-	88.65	-
Nuclear Fission	2,156	8,653		11.19 GJ/MWh	174.23	3.39
Nuclear Fission – SMR	300	8,867		10.60 GJ/MWh	136.07	4.30
Hydroelectric	400	14,545		-	42.77	-
Combined-Cycle	418	1,553		6.79 GJ/MWh	20.20	3.65
Combined-Cycle with CCUS	377	3,554		7.52 GJ/MWh	39.53	18.28
Combined-Cycle with CCUS (Retrofit)	-10%	2,001		-10% reduction in efficiency	39.53	18.28
H2 or NG Simple-Cycle – Frame	233	1,021		10.45 GJ/MWh	10.03	6.45
H2 or NG Simple-Cycle – Aeroderivative	105	1,683		9.63 GJ/MWh	23.35	6.73
H2 or NG Combined-Cycle	418	1,553		6.79 GJ/MWh	20.20	3.65
Battery Energy Storage	50 MW, 200MWh	2,104	1,394	83%	57.28	-
Compressed Air Energy Storage	100 MW, 10hr	1,648		52%	21.76	-
Pumped Hydro Energy Storage	100 MW, 10hr	3,543		80%	38.05	-

Preliminary Scenario Emissions



- Emissions above do not include emissions from Cogeneration
- Decarbonization by 2050 achieves an 89% reduction in 2032 relative to carbon emissions in 2022
- Decarbonization by 2035 achieves a 91% reduction in 2032 relative to carbon emissions in 2022
- Vast majority of emissions reduction due to Coal-to-Gas retirements and CCUS retrofits on Combined-cycle
  - Remaining emissions difference between scenarios after 2030 due to non-abated combined-cycle

2024 LTO and Resource Adequacy Modeling

- The assessment utilizes the resource adequacy model (RAM) to evaluate the generation and load forecasts constructed for the 2024 LTO.
  - At a high level, the 2024 LTO preliminary Decarbonization by 2035 forecast assumes the current market structure, an unconstrained transmission system and current carbon policies (Carbon price, ERP, TIER, CER)
  - The scenario resource mix is determined by **economic** builds under current market structure with no reserve margin assumed (i.e., model adds/subtracts units based on their forecasted economics)
- The RAM determines the impact of the modelled supply mix capacity (MW) on resource adequacy (EUE MWh) using a probabilistic approach that varies load and generation
  - Hourly chronological dispatch using a stochastic (Monte Carlo) simulation
  - Distribution for load/weather, load growth uncertainty, outages, intermittent renewable output, intertie, and emergency operating procedures
- This assessment evaluated resource adequacy and the associated risk of unserved energy for 2035 and 2038 as well as several sensitivities
- The results are measured against the Long-term Adequacy Threshold as outlined in Section 202.6 (6) of the ISO rules, Adequacy of Supply. The EUE threshold is calculated as the 1-hour average Alberta internal load for a year divided by 10.

52

Preliminary Resource Adequacy

Study	Forecast year	EUE (MWh)
Decarb by 2035 – Unmanaged Load w/ Cogen Defection	**2035**	**36,000**
Decarb by 2035	2035	35
Decarb by 2050	2035	3
Decarb by 2035	2038	42,300
Decarb by 2050	2038	10,700
Decarb by 2035 - 1,600 MW Cogen Defection	2035	25,400
Decarb by 2035 - 1,600 MW Cogen Defection	2038	830,000
Decarb by 2035 - No CCUS Retrofits*	2038	3,000,000
Decarb by 2035 - 1,800 allowable hours	2038	15,400

- Resource Adequacy threshold (EUE) is approximately 1,135 MWh for 2035/2038
- Unmanaged Load – Electric vehicle (EV) load shifting (load management) has not been integrated into load forecast to reflect the potential to mitigate EV coincidental load peaks when penetration levels increase.
  - The remaining scenario/sensitivity are all run with a managed load profile with some load shifting adjustment to non-peak hours.
- Cogeneration Defection – Assumes that ~1,600 MW of Cogeneration that currently supplies energy net to grid is removed due to uncertainty and inability to comply with the draft CER parameters with regards to behind-the-fence generation
- No CCUS Retrofits – Assumes that ~2,400 MW of natural gas generation CCS retrofits do not occur or occur but do not meet 30t/GWh standard and thus are constrained to 450 hours annual operations.
- 1,800 allowable hours – Testing assets assumed within the preliminary Long-term Outlook Decarbonization by 2035 forecast that are unabated and are limited to 1,800 allowable hours as opposed to the current draft 450 allowable hours.

Next Steps

Public

Stakeholder Engagement Timeline

- On June 8, 2023, the AESO hosted a preliminary results engagement session regarding the 2024 (LTO)
- By June 22, 2023, the AESO had received written responses from 18 stakeholders, representing electricity generators, consumers, academic organizations and other interested parties[1,2]
- Another opportunity to provide written feedback is being provided from November 15, 2023 until December 6, 2023
  - More details regarding this feedback request are available on Forecasting Insights | AESO Engage.
- The AESO will continue to work with stakeholders to understand their concerns and perspectives regarding generation and load transformation

1 Consolidated feedback from June 8th-22nd, 2023
2 AESO Directional Summary Report

Further Analysis – Scenarios

- Alternate Decarbonization
  - Qualitatively and quantitively explore the benefits and challenges of increased intertie connection with neighboring jurisdictions
  - Anticipated technological costs and development timelines associated with CCUS and hydrogen development are delayed, and performance is below expectations
  - Explore what alternate additional low emission technologies can bridge the gap
- High Electrification
  - Explore the anticipated decarbonization of the grid, the pace and scale of electrification is increased to take advantage of the economy wide potential to reduce emissions
  - The pace and scale of electrification in the transportation, buildings and heavy industry sectors are sped up to take advantage of a lower emission power grid

Updated Further Analysis – Insights

- Resource Adequacy
  - The AESO will evaluate resource adequacy for the Reference Case and scenarios utilizing its electric system risk model and the associated risk of unserved energy
- Emission Outcomes
  - Exploration of the opportunities for sectoral emissions reduction, plus analysis regarding forecast aggregate greenhouse gas emission performance from the Reference Case and scenarios
- Cost
  - Generic levelized cost of electricity estimates for technology types

Next Steps

- December 6, 2023 | Stakeholder feedback due
- December 11, 2023 | Stakeholder feedback will be shared on AESO Engage
- January 2024 | Publish a summary directional update
- Early Q2-2024 | Publish 2024 Long-term Outlook Report

Request for Feedback

- The AESO values stakeholder input and invites all interested stakeholders to provide their feedback on the 2024 LTO Preliminary Results via the questions in the **Stakeholder Feedback survey on or before December 6, 2023**
  - The Stakeholder Feedback survey will be open for feedback beginning on November 15, 2023, and the survey will be located on the Forecasting Insights page under the Stakeholder Feedback tab on AESO Engage

Thank you