Results

Implications, Insights and Outcomes

AESO 2024 Long-Term Outlook

MAY 2024

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Overview

- If substantial investment tax credits (ITC) for combined-cycle with carbon capture, utilization and storage (CCUS) and emissions performance credits (EPCs) for solar and wind are available, these generation technologies represent the most cost-competitive generation resources from a levelized cost perspective. Nuclear small modular reactor (SMR) technology is cost competitive with unabated natural gas-fired generation technologies on a levelized basis using first-of-a-kind installation estimates.
- Due to the rising cost of emissions and declining high-performance benchmarks (HPB for electricity, hydrogen-fired combustion technologies reach cost parity with their unabated natural gas counterparts by the year 2038 and become more cost competitive on an annualized basis thereafter.
- After adjustments to electric vehicle load profiles, the supply forecasts for the Reference Case, High Electrification and Alternative Decarbonization scenarios are expected to be sufficient to meet adequacy standards in the 2028, 2030, 2033, 2035, and 2043 base years. However, for all scenarios, 2038 has significant risk given mandated retirement dates for the coal-to-gas assets.
- The Decarbonization by 2035 scenario poses the highest risk for load shedding and unserved energy, with expected unserved energy (EUE) reaching as high as 174,000-unit megawatt hour (MWh), mostly in high demand winter months.
- By 2035, forecast emissions from all scenarios represent a 94 per cent to 96 per cent reduction from 2005 levels, demonstrating a significant reduction in Alberta's electricity sector emissions. Electricity sector carbon emissions for all scenarios differ from the Reference Case by less than two megatonnes (Mt) per year throughout the 2024 *Long-Term Outlook* (LTO) timeframe.

Costs

Levelized Cost of Electricity

The levelized cost of electricity (LCOE) is the net present value of the forecast cost of electricity production, on a MWh basis, from a generation resource, from commercialization to retirement. As a metric for the determination of the financial viability of capital investment into a generation project, the LCOE is influenced by several key factors including, but not limited to, cost projections, production projections, physical plant characteristics and prevailing financing rates. With the continued push towards decarbonization of the electrical gird, many new and emerging technologies also benefit from cost reductions via ITCs and the generation of bankable emissions offsets or EPCs, which directly affect their cost of generation through the prevailing price of carbon. Table 1 and Table 2 outline the cost assumptions used in this LCOE calculation.

Table 1: Technology Cost Assumptions for Natural Gas- and Hydrogen-fired Generation

Generator Inputs	Combined -Cycle	Combined-Cycle with CCUS[a]	Simple-Cycle aeroderivative	Simple-Cycle frame	Hydrogen-fired Simple-Cycle aeroderivative	Hydrogen-fired Simple-Cycle frame	Hydrogen-fired Combined-Cycle
Unit size (MW)	418	377	105	233	105	232	418
Capacity factor, %	75	85	38	38	38	38	85
Overnight capital cost, $/kW	1,553	3,554	1,683	1,021	1,683	1,021	1,553
Overnight capital cost with ITC, $/kW	N/A	2,320	N/A	N/A	1,431	868	1,320
Fixed operating cost, $/kW	20.20	39.53	23.35	10.03	23.35	10.03	20.20
Variable operating cost, $/kW	3.65	8.36	6.73	0.86	6.73	0.86	3.65
Heat rate, GJ/MWh	6.79	7.52	9.63	10.45	9.63	10.45	6.79
Natural gas emission factor kg CO_2/GJ	56.10	56.10	56.10	56.10	0	0	0
Capture rate, %	0	93	N/A	N/A	N/A	N/A	N/A
Useful Life, years	30	30	25	25	25	25	30
Total lead time before commissioning, years	4	5	4	4	4	4	4
Base year	2022						
Pre-tax WACC, %	10.50						
Inflation, %	2.00						

[a] United States Energy Information Administration (EIA) Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies

Table 2: Technology Cost Assumptions for Other Generation

Generator Inputs	BESS (Li-Ion), 4hr[b]	Natural Gas Fuel Cell[b]	CAES, 10hr[c]	PHES, 10hr[c]	Dammed hydro[d]	Nuclear [a]	Nuclear SMR[a]	Solar [b]	Wind[b]
Unit size (MW)	20	10	100	100	400	2156	600	50	100
Capacity factor, %	21	50	25	25	50	90	90	20	39
Overnight capital cost, $/kW	2,104	9,596	1,681	3,614	14,545	8,653	8,867	1,687	1,563
Overnight capital cost with ITC, $/kW	1,473	6,718	1,177	2,530	12,363	7,355	6,207	1,181	1,094
Fixed operating cost, $/kW	57.30	44.09	22.19	38.06	42.77	174.23	136.07	36.51	88.65
Variable operating cost, $/kW	2.60	0.85	0	0	0	3.39	4.30	0	0
Heat rate, GJ/MWh	N/A	6.83	N/A	N/A	N/A	11.19	10.60	N/A	N/A
Natural gas emission factor, kg CO_2/GJ	0	56.10	0	0	0	0	0	0	0
Capture rate, %	0	0	0	0	0	0	0	0	0
Useful Life, years	10	20	30	40	40	40	40	25	30
Total lead time before commissioning, years	2	2	4	4	6	6	6	4	4
Base year	2022								
Pre-tax WACC, %	10.50	10.50	10.50	10.50	10.50	10.50	10.50	7.00	7.00
Inflation, %	2.00								

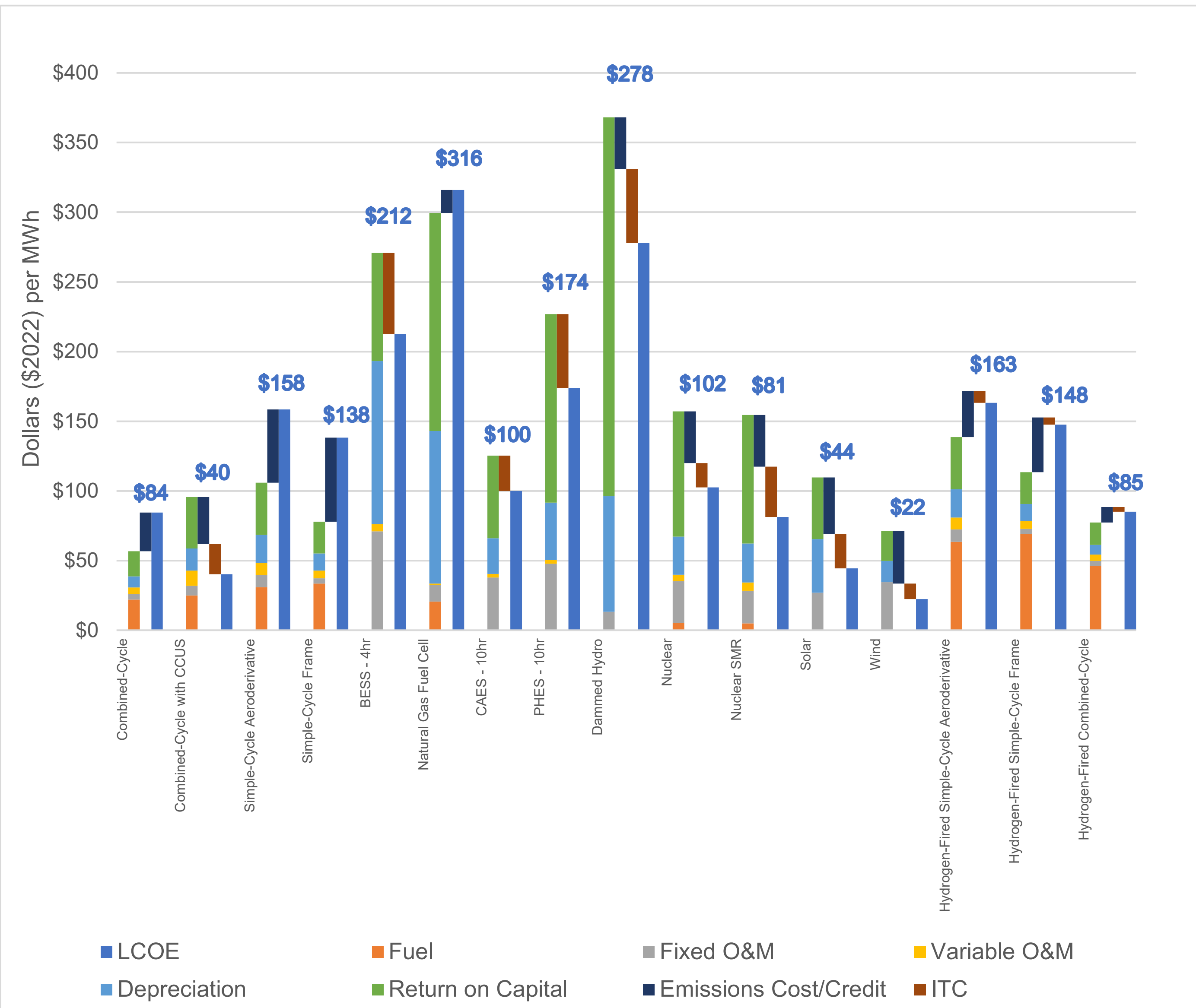
[a] EIA Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies
[b] Guidehouse Forecasting Services Data – prepared under contract for the AESO
[c] Pacific Northwest National Laboratory (PNNL) – 2022 Grid Storage Technology Cost and Performance Assessment
[d] BC Hydro Site C CAPEX Estimate

Assumptions

All project costs are assumed to have a weighted average cost of capital (WACC) of 10.50 per cent (except for wind and solar, which are set to seven per cent, reflecting an expectation that these facilities will be developed under lower risk, long term corporate power purchase agreements) and are depreciated based on applicable tax provisions over the lifetime of the generation project. Cost escalation is assumed to be two per cent annually and is applied across all technologies. Costs are baselined for representation in 2022 dollars and, unless otherwise noted, reflect the application of ITCs available for a given technology. The cost analysis presented here applies to the Reference Case scenario unless explicitly stated otherwise.

Prevailing emissions performance guidelines are modelled based on the current *Technology Innovation and Remissions Reduction* (TIER) *Regulation* schedule and the posted federal price of carbon until 2030. Post-2030, the TIER HPB for electricity is assumed to decline linearly to zero by 2050, except in the Decarbonization by 2035 scenario, in which the HPB declines to zero by 2035, while the price of carbon is assumed to increase in line with a two per cent annual escalation. Non-storage-based low or no emissions technologies such as combined-cycle with CCUS, nuclear, wind and solar are assumed to generate EPCs or emissions offsets when a generator's emissions levels are below the HPB for electricity, based on the prevailing price of carbon. This revenue source is presented as a reduction to their LCOE. Figure 1 shows the LCOE for select generation technologies broken out by cost component.

Figure 1: Levelized Cost of Electricity by Cost Component for Select Technologies

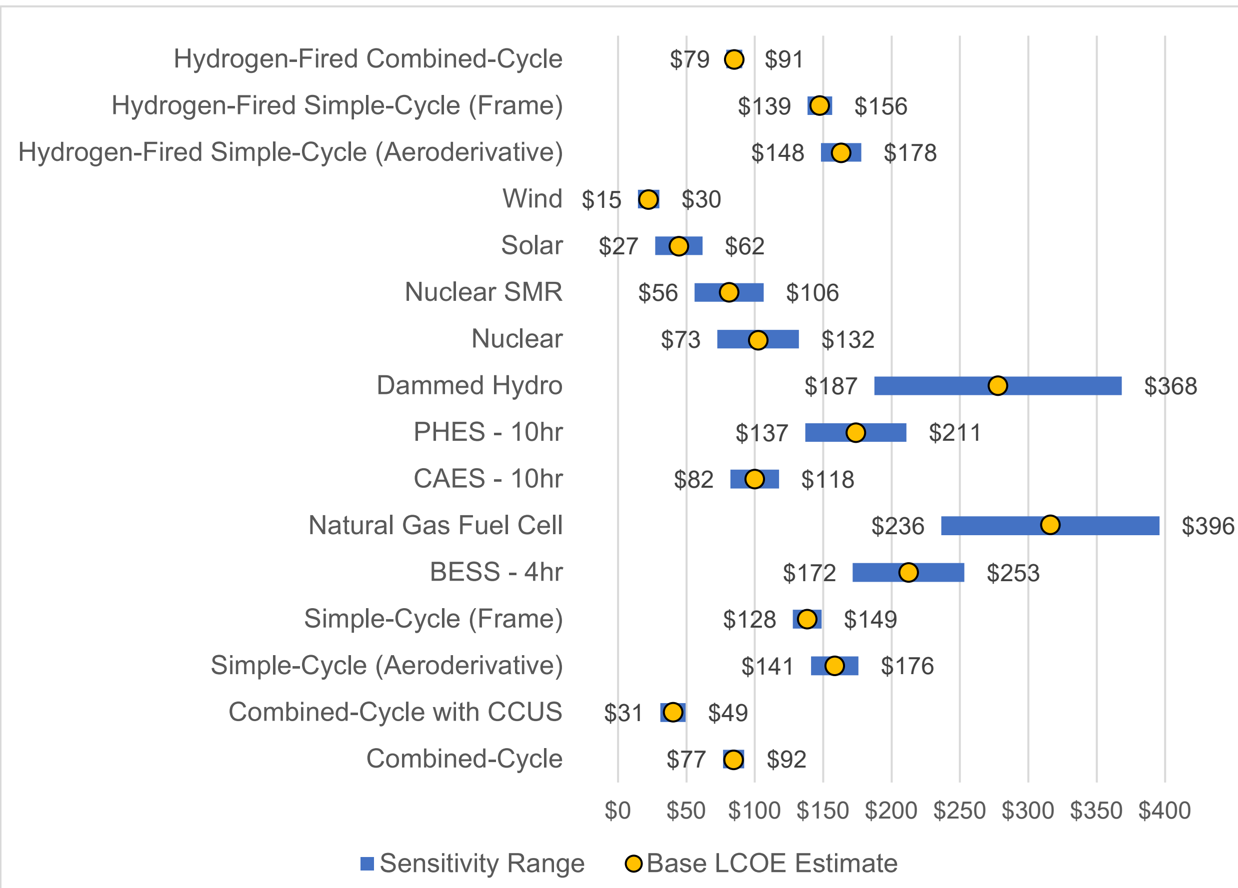


Modeled on the potential availability of substantial ITCs for combined-cycle with CCUS and EPCs for solar and wind, these generation technologies represent the most cost-competitive generation resources from a levelized cost perspective. Large upfront capital costs make natural gas fuel cells and dammed hydro the most expensive generation technology, while low-capacity factor assumptions and high upfront costs result in high LCOE figures for battery storage (lithium ion). It is also worth noting that nuclear SMR levelized costs are forecast to be more cost competitive than unabated dispatchable technologies, coming in at a discount to both unabated combined and simple-cycle natural gas units.

Sensitivities

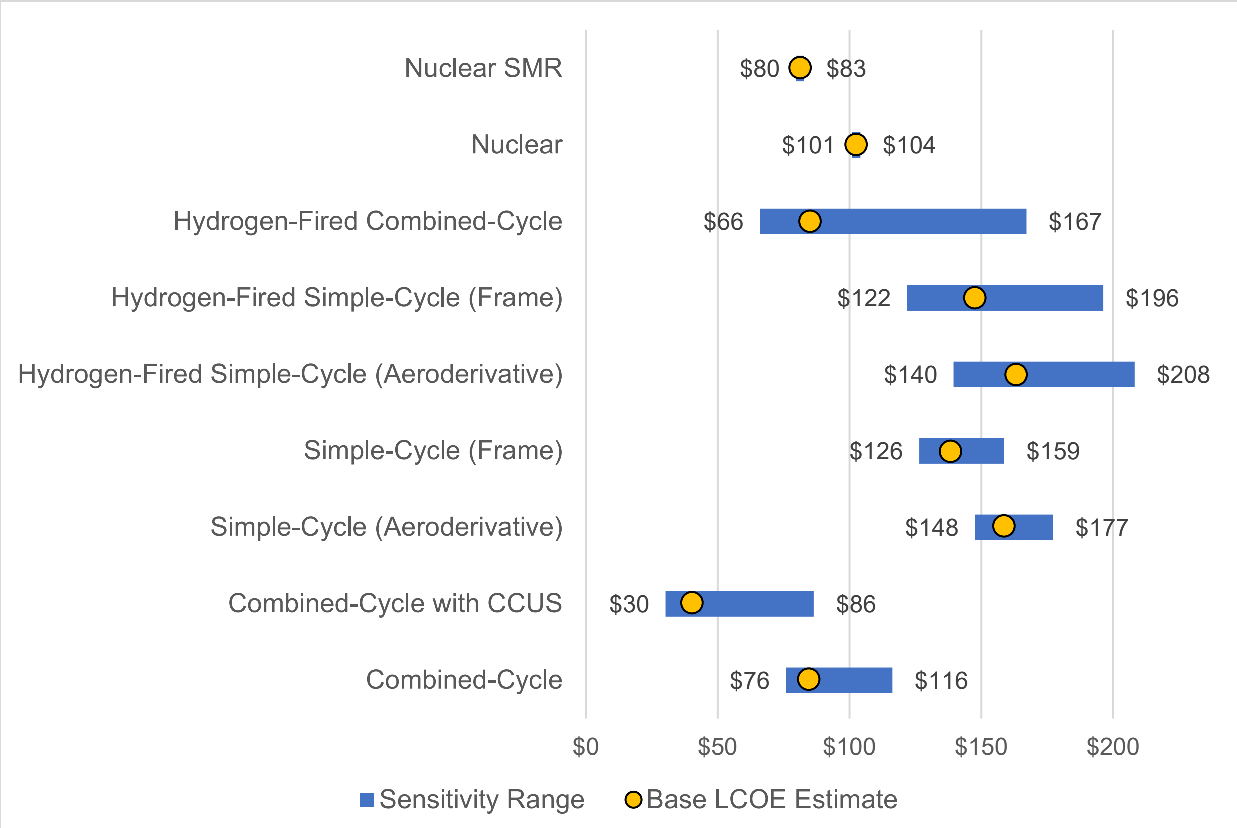
The LCOE is driven by several cost and plant-specific assumptions, which can cause the calculation to vary widely. Sensitivities demonstrate a range of levelized costs due to changes in overnight capital cost, fuel cost (for combustion technologies), WACC and plant capacity factor. Figure 2 illustrates the change in LCOE for a ±30 per cent deviation in capital costs.

Figure 2: Capital Cost Sensitivity of Levelized Cost of Electricity for Select Technologies Combustion Technologies



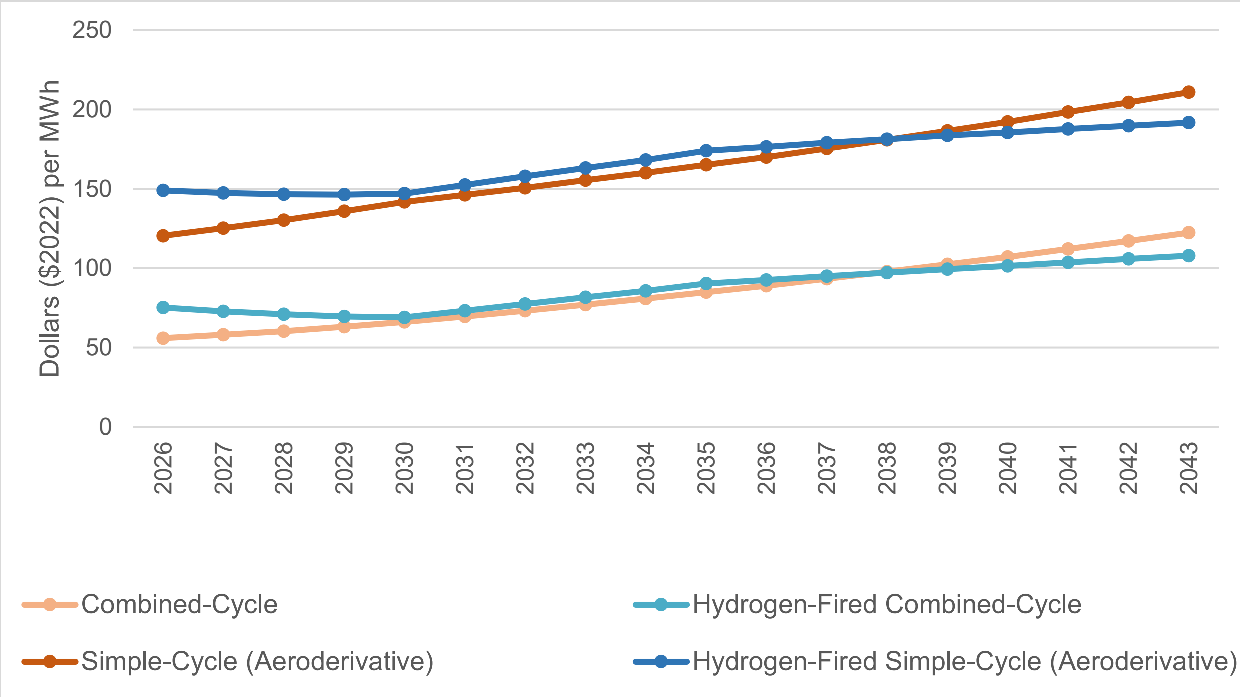
Natural gas and hydrogen-fired technologies are sensitive to the input price of fuel used in the generation process. Figure 3 illustrates the change in LCOE for a ±30 per cent deviation in fuel costs for combustion generators.

Figure 3: Fuel Sensitivity (±30 per cent) of Levelized Cost of Electricity for Select Technologies



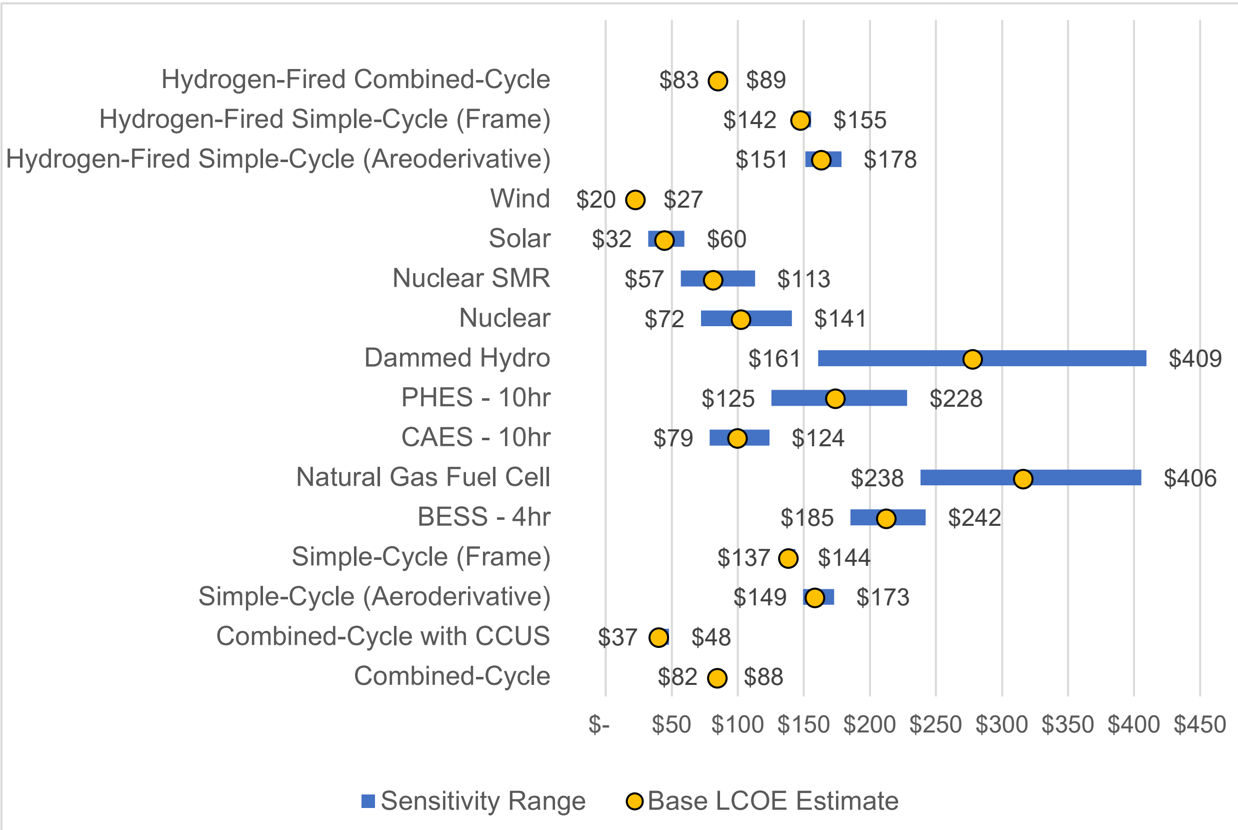
Natural gas- and hydrogen-fired turbines are assumed to operate with the same capital cost structure and operational efficiency related to electrical generation. With these assumptions, it is possible to compare the annualized cost of generation for the different fuel types and gauge their competitiveness. While hydrogen fuel is more expensive on an energy content basis, the technology benefits from being zero-emission and thus avoids any emissions performance payments related to underperforming the TIER electricity HPB. However, under TIER, hydrogen-fired generators are required to report emissions related to the production of imported hydrogen used for electrical generation based on the HPB for hydrogen. This results in hydrogen-fired generators paying an allowable emissions-based true-up which increases the cost of energy for this fuel type. Due to the rising cost of carbon and declining HPB for electricity, hydrogen-fired combustion technologies reach cost parity with their unabated natural gas counterparts by the year 2038 and become more cost competitive on an annualized basis thereafter. ITCs available on the production side of the hydrogen facilities for CCUS (e.g., blue hydrogen) serve to suppress the fuel cost for associated hydrogen-fired power generation facilities. This is illustrated in Figure 4 which shows the forecast in cost differences for combined-cycle and simple-cycle generators operating on the different fuel types.

Figure 4: Annualized Generation Costs for Natural Gas- and Hydrogen-fired Technologies



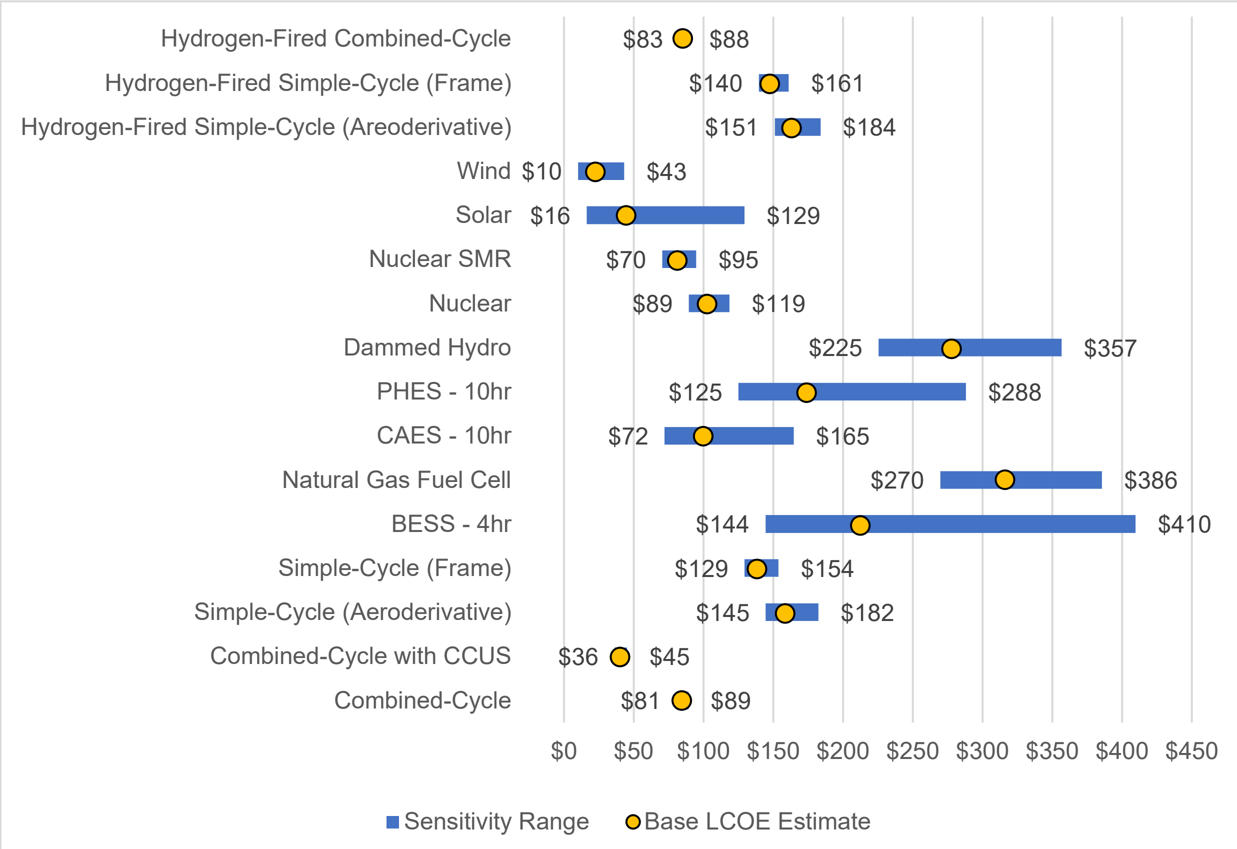
The pre-tax WACC determines the required return on investment that a generator must achieve over its lifetime to be considered an economic investment. Changes to the prevailing WACC influence the LCOE for a generation project. Figure 5 demonstrates the sensitivity of the LCOE to a WACC range of 5.5 to 15.5 per cent.

Figure 5: Weighted Average Cost of Capital Sensitivity (5.5 to 15.5 per cent) of Levelized Cost of Electricity for Select Technologies



Changes in capacity factor for the various generation technologies can have a material effect on their LCOE, as costs are distributed over a larger or smaller energy base. The sensitivity of the LCOE to a 10 per cent gross change in capacity factor from base assumptions is exhibited in Figure 6. The resulting change in LCOE is highest for technologies with low-capacity factors and proportionately high capital costs such as battery storage, solar and hydro. Mid-merit and baseload technologies, such as combined-cycle and nuclear, show smaller shifts in LCOE based on capacity factor variability due to their relatively large energy base.

Figure 6: Capacity Factor Sensitivity (±10 per cent) of Levelized Cost of Electricity for Select Technologies

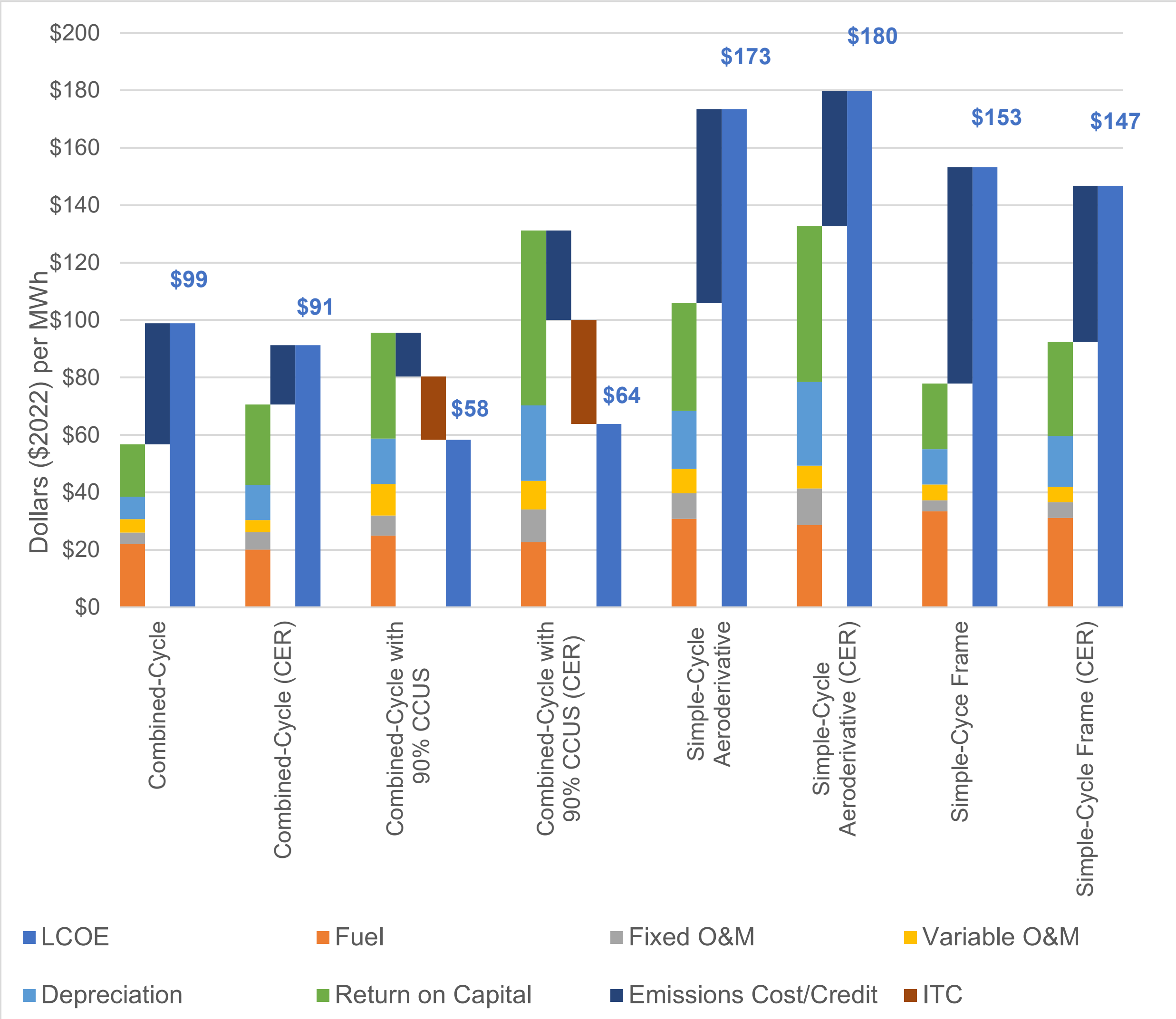


Clean Electricity Regulations (CER)

The federal CER, as published in the Canada *Gazette I,* would impose a 30 tonne carbon dioxide equivalent per gigawatt hour (GWh) emission performance standard beginning January 1, 2035, on any electricity generating units greater than 25 megawatt (MW) that use any amount of fossil fuels and operate for more than 450 hours per year.[1] These restrictions would result in a significant increase on the operating costs of unabated thermal generators and abated generators which do not achieve a sufficient carbon capture rate (e.g., greater than 93 per cent) to meet the emission performance standard. In the following analysis, it is assumed that the TIER HPB for electricity declines linearly to zero by the year 2035 to coincide with the commencement of the CER and that generic combined-cycle with CCUS units will operate with a capture rate of 90 per cent which would make them subject to CER output limitations post 2035.

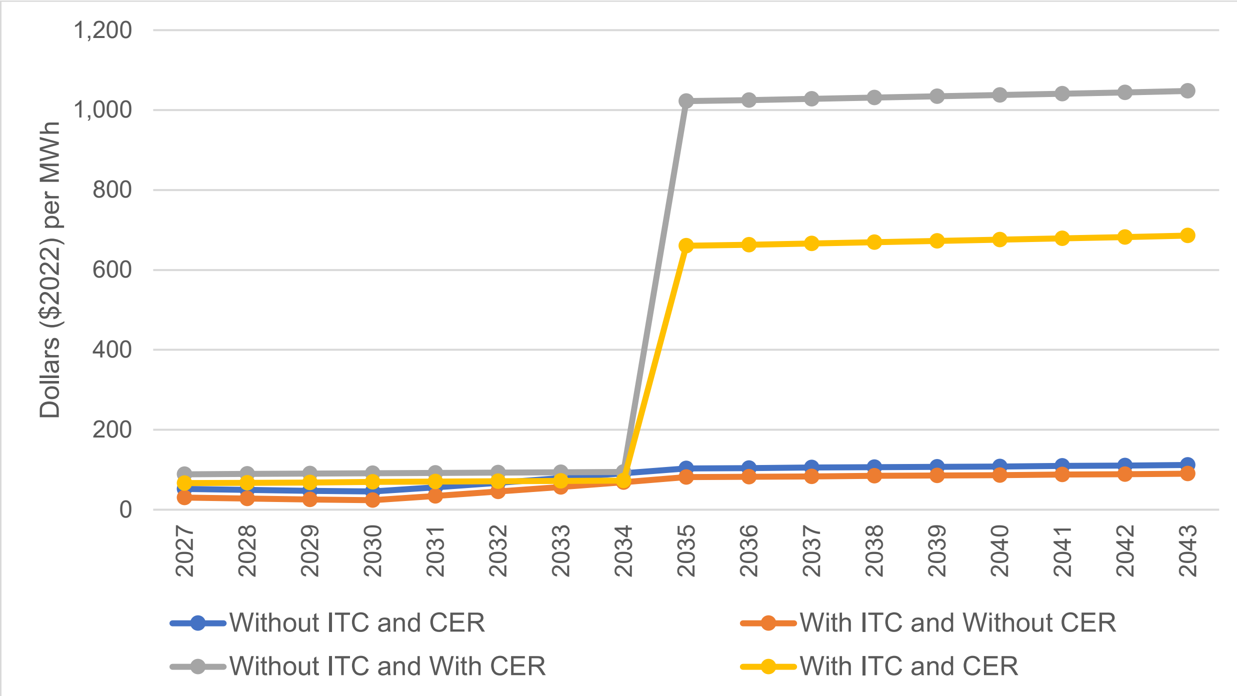
[1] For more information on assumptions regarding the CER in the 2024 LTO, see the Policy and Regulatory Drivers section.

Figure 7: Sensitivity of Levelized Cost of Electricity to the CER for Combustion Technologies



On a levelized basis, the CER results in a small decrease in the levelized cost for unabated combined-cycle and simple-cycle frame generators. For these generators, the savings in emissions payments outweigh the coincident increase in the required return on capital over the project's lifetime due to a reduced energy base. Conversely, abated combined-cycle and unabated simple-cycle aeroderivative generators see an increase in levelized cost under the CER. In this case, the increase in required return on capital outpaces an increased emissions offset amount. As compared to unabated simple-cycle frame generators, unabated simple-cycle aeroderivative generators experience a larger reduction in emissions payments due to their more efficient heat rates. The impacts of the CER are more prominently seen on an annualized basis, where the 2035 start date results in a large increase in operating costs due to limited energy production in the event that abated and unabated technologies are unable to achieve the stringent requirements of the CER (Figure 8).

Figure 8: Annual Cost Estimates for Combined-Cycle with CCUS Units with and without ITCs and CER



Resource Adequacy Outcomes

The AESO used a probabilistic model to assess resource adequacy for specific years within the 2024 LTO. In addition, the AESO evaluated sensitivities for each scenario where potential risks were identified. The base years selected are 2028, 2030, 2033, 2035, 2038 and 2043 for a full balanced view of the forecast horizon. The Resource Adequacy Model (RAM) determines the tradeoff between capacity (MW) and reliability (expected unserved energy [EUE] MWh) using a probabilistic approach that varies load and generation. The results are measured against the Long-Term Adequacy Threshold outlined in Section 202.6 (5) of the ISO rules, Adequacy of Supply.[2]

The AESO utilizes the Strategic Energy and Risk Valuation Model (SERVM) software to house its RAM. SERVM is an electric system risk model designed to perform resource adequacy studies and sensitivities. It conducts hourly chronological simulations which model a full distribution and correlations of weather years that impact load, thermal temperature derates and intermittent generation output from renewables. The model combines these parameters with a Monte Carlo simulation of generator outages to provide a full distribution of physical reliability metric outcomes.

The AESO runs 7,500 iterations for a given resource mix defined within each scenario. Each iteration considers 25 years of weather data (including load and renewables profiles 1998 - 2022), five load forecast economic scenarios, and 60 unit-outage draws to capture uncertainty around the frequency and durations

[2] https://www.aeso.ca/rules-standards-and-tariff/iso-rules/section-202-6-adequacy-of-supply/

of outages. The iterations are run annually, hourly and chronologically to account for storage charging and discharging behavior, and for the frequency and duration of thermal outages.

Supply shortfalls have many drivers, including high load, low conventional generator availability, low variable resource output, low water inflows to energy-limited hydro, and low or zero intertie availability. Developing robust results requires accurately characterizing the magnitude of uncertainties associated with each driver. It is important to review the underlying drivers of historical reliability events and ensure that the key drivers are represented in the RAM.

The AESO's 2024 LTO long-term capacity expansion tool does not include any planning reserve margin (PRM) in the system to reflect the energy-only structure of the Alberta electricity market.

Resource Adequacy Metrics

The standard metrics used in resource adequacy and in the following sections include:

Expected Unserved Energy (EUE): the expected amount of load (MWh) forecast to be unserved in a given forecast year.[3] This metric considers the magnitude of the shortfall.

Loss of Load Expectation (LOLE): Under this metric, an event is considered to have occurred whenever any amount of load in a day, however small, has not been met. It is the count of days with EUE in any hour. This metric considers the frequency of the shortfall.

Loss of Load Hours (LOLH): Under this metric, an event is considered to have occurred if any amount of shortfall has occurred in that hour. This metric considers the duration of the shortfalls.[4]

Resource Adequacy Results

The AESO analyzed four forecast scenarios: the Reference Case, Decarbonization by 2035, Alternative Decarbonization and High Electrification.

Reference Case

For the Reference Case, the AESO simulated the years 2028, 2030, 2035, 2038 and 2043. In the Reference Case, the RAM models incorporate the resource mix from each year and quantified risks in the forecast study years. The intertie capability for the reference case is assumed to be 1,200 MW until 2029. Additional intertie capability is expected to be added through intertie restoration, bumping the capability for the study years 2030, 2035, 2038 and 2043 to 1,600 MW. Table 5 shows the results for the resource adequacy Reference Case.

Table 5: EUE, LOLE, and LOLH Metrics for the Reference Case

Year	EUE (MWh)	LOLE (# of days)	LOLH (hours)	Long Term Adequacy Threshold (MWh)
2028	0	0	0	1,054
2030	0	0	0	1,060

[3] The EUE threshold is calculated as the one-hour average Alberta internal load for a year divided by 10. For example, if the average hourly load in Alberta is 10,000 MW, then the reliability threshold would be 1,000 MWh for that year.

[4] The typical reliability target for this metric is often set at 0.1 days/year (one day experiencing an event in 10 years).

Year	EUE (MWh)	LOLE (# of days)	LOLH (hours)	Long Term Adequacy Threshold (MWh)
2033	0	0	0	1,098
2035	0	0	0	1,133
2038	4,400	5.1	11.1	1,171
2043	276	0.8	1	1,270

As shown in Table 5, the risk of experiencing a supply shortfall is extremely low until the year 2038. The forecast supply mix for the Reference Case is sufficient and meets various forecast load levels while accounting for weather and economic uncertainty. The year 2038 shows an increase in supply shortfall that is largely attributed to the coal-to-gas converted unit retirements. The retirements come in at the end of 2037 when the end-of-life extensions under the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* bind.

Figure 9 and Figure 10 show the monthly distribution of the EUE for the years 2038 and 2043, respectively. On the left and bottom axes, the monthly EUE distribution is plotted. On the right and top axes, the hourly percent of EUE distribution is plotted.

Figure 9: Decarbonization by 2050 Monthly and Hourly EUE Distribution for the Year 2038

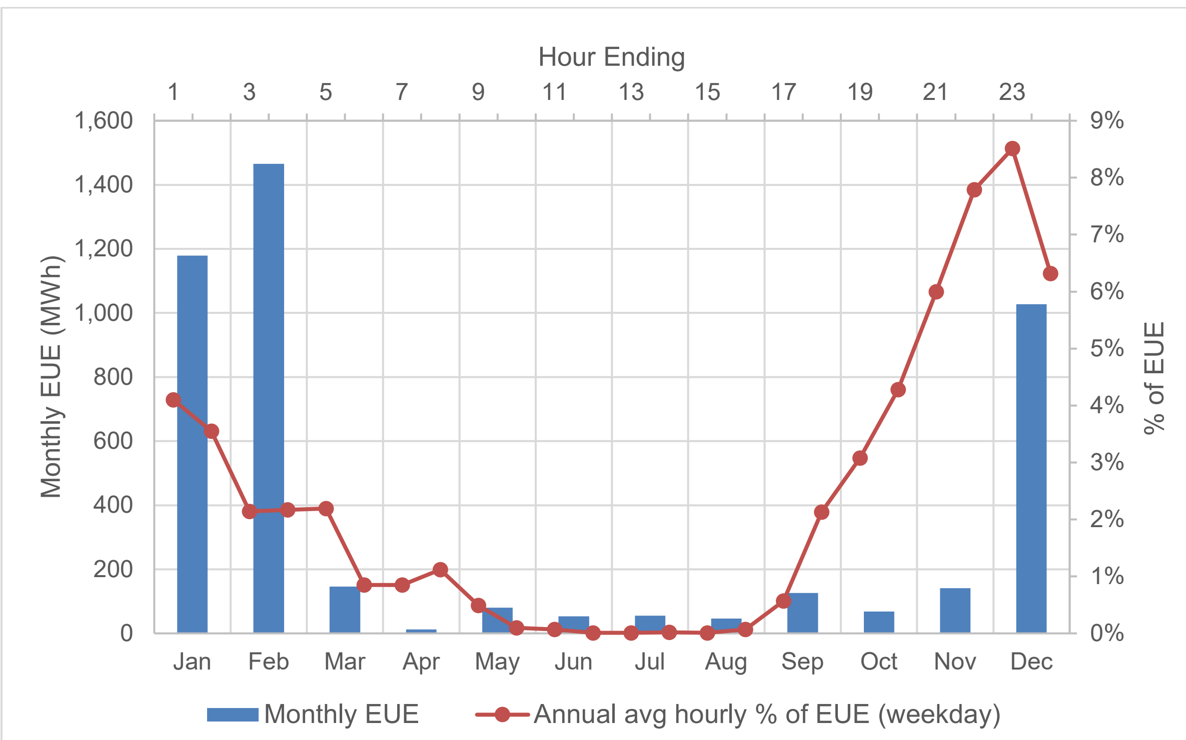
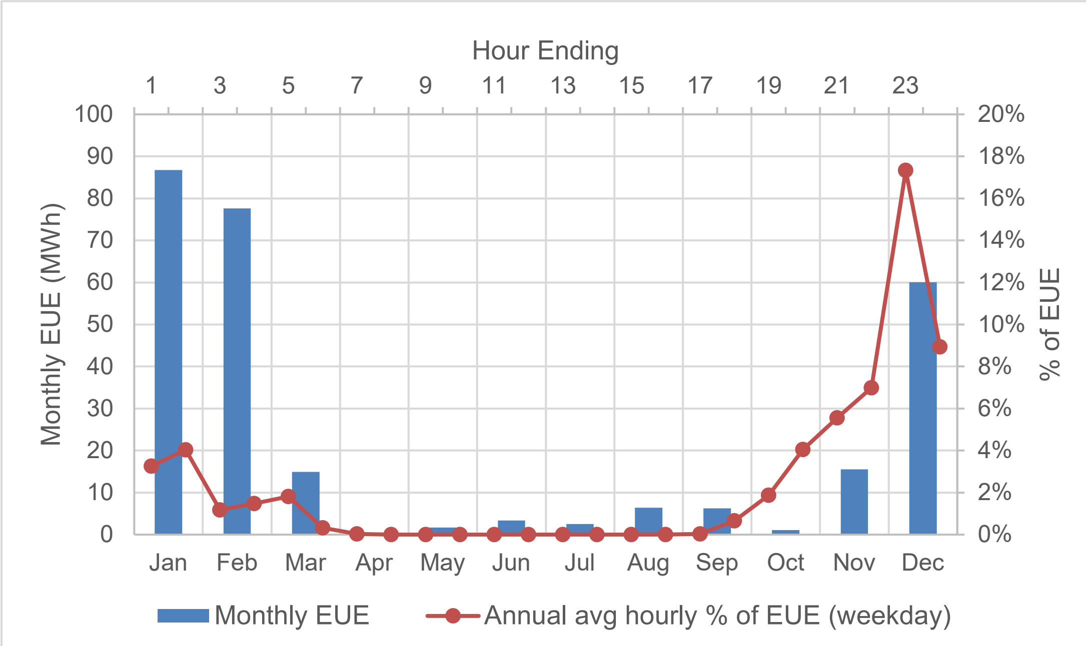


Figure 10: Decarbonization by 2050 Monthly and Hourly EUE Distribution for the Year 2043



Figures 9 and 10 show a similar pattern in which the highest risk of EUE remains in the winter months, when the load is highest in the province. The supply shortfall number for 2043 is not concerning as it is lower than the long-term adequacy threshold defined above. Moreover, the optimal generation mix for the year 2043 includes substantial baseload of nuclear generation that compensates for the coal-to-gas retirements. However, the year 2038 does cross the long-term adequacy threshold, and the AESO could take action to avoid supply shortfall for that year and bring the EUE down under the defined threshold in Section 202.6 (5) of the ISO rules. This result is expected, given the large number of MWs leaving the supply stack from the retirement of the coal-to-gas units.

The EUE hourly distribution shows that the highest risk hour has shifted to Hour Ending (HE) 23. This phenomenon is largely due to the managed load profiles associated with electric vehicle (EV) charging patterns.[5] Moreover, it is expected that storage systems would be exhausted through the traditional high-risk, peak hours (HE 16 – 19) leaving little stored energy behind for the EV peak charging hours, such as HE 23. It is important to note that the charging patterns for EVs are expected to be dynamic to avoid high prices attributed to EVs charging at the same time increasing both demand and price. Dynamic charging based on price response will most likely decrease the risk of EUE during HE 23 and the off-peak hours.

[5] For more information on electric vehicle methodology in the 2024 LTO, see the Load Methodology section.

Decarbonization by 2035

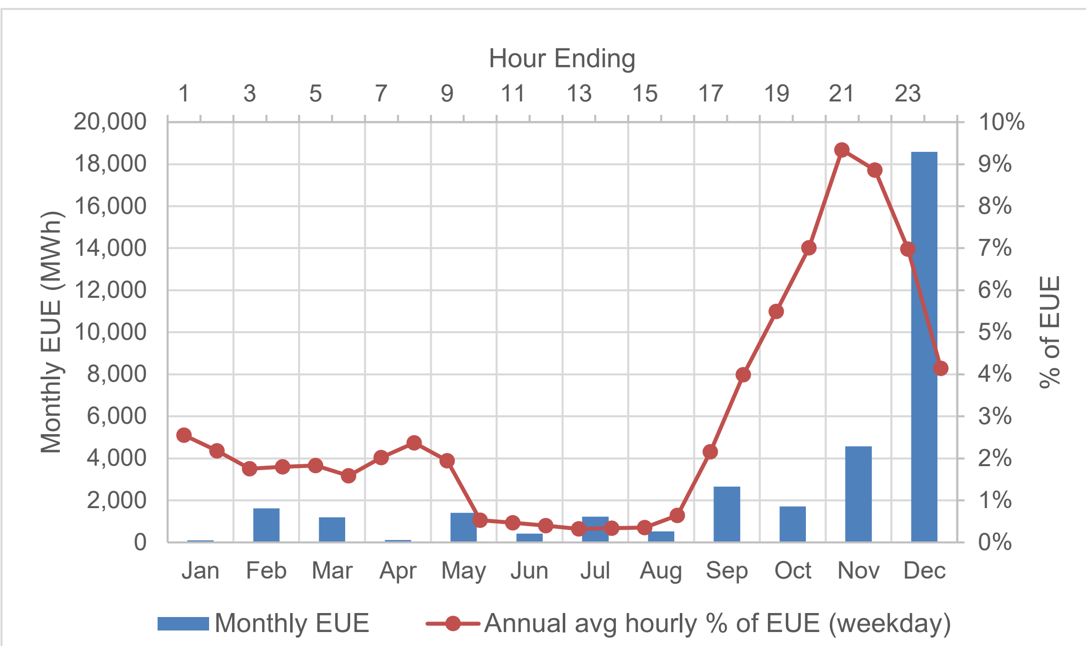
In this scenario, the AESO assumes an accelerated timeline towards decarbonization in which the TIER HPB for electricity reaches zero tonnes carbon dioxide ermissions per MWh by 2035, and unabated thermal generators are constrained to operating parameters described in the CER as published in the *Canada Gazette 1*.[6] The AESO simulated the years 2035 and 2038 as the base years for this scenario to compare against the reference case scenario.

Table 6: EUE, LOLE, and LOLH Metrics for Decarbonization by 2035

Year	EUE (MWh)	LOLE (# of days)	LOLH (hours)	EUE Threshold (MWh)
2035	34,131	19.4	68.3	1,133
2038	173,686	67.45	284.9	1,171

As seen from Table 6, the supply shortfall increases substantially compared to both the reference case and the supply shortfall threshold defined by the AESO Reliability Standards. The optimal resource mix for this scenario is not sufficient to meet the forecast load levels for the base years. This is largely attributed to the limitations imposed by the CER on unabated gas units that are greater than 25 MW in capacity. Such units are not allowed to run more than 450 hours per year, limiting available supply in the merit order for the majority of the year. This limitation provides an incentive for unabated units to use their hourly allocation during January and February, which are high-demand months, and remain dormant for the rest of the year. The impact of the 450-hours limitation is best illustrated in Figure 11 below.

Figure 11: Decarbonization by 2035 Monthly and Hourly EUE Distribution for the Year 2035



[6] For more information about assumptions regarding TIER and CER in the 2024 LTO, see the [Policy and Regulatory Drivers section](#).

Figure 12: Decarbonization by 2035 Monthly and Hourly EUE Distribution for the Year 2038

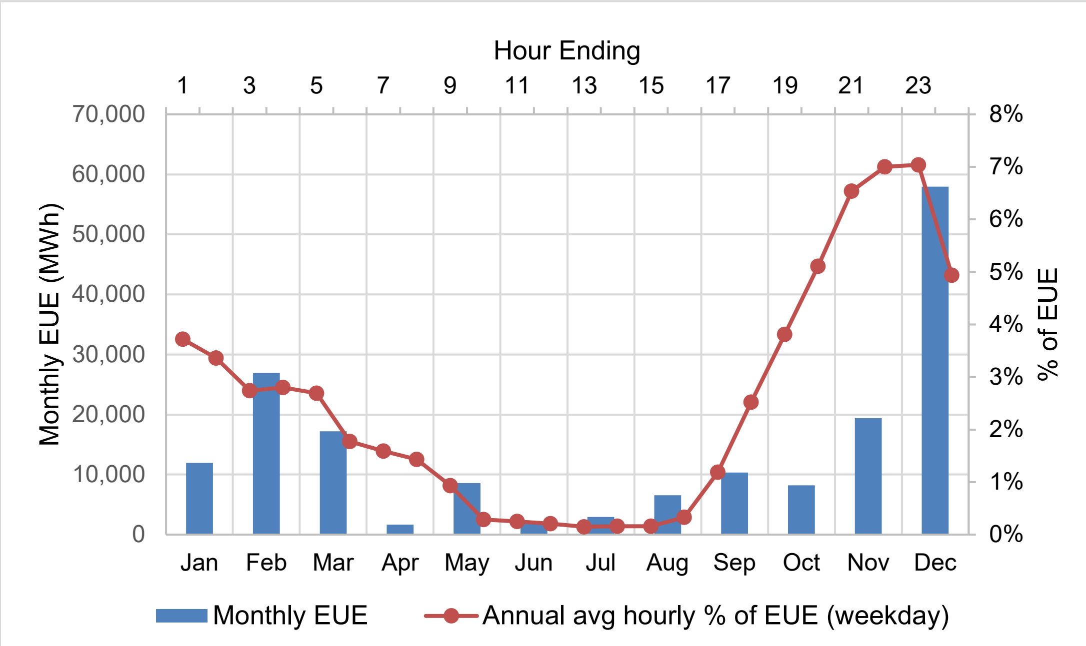
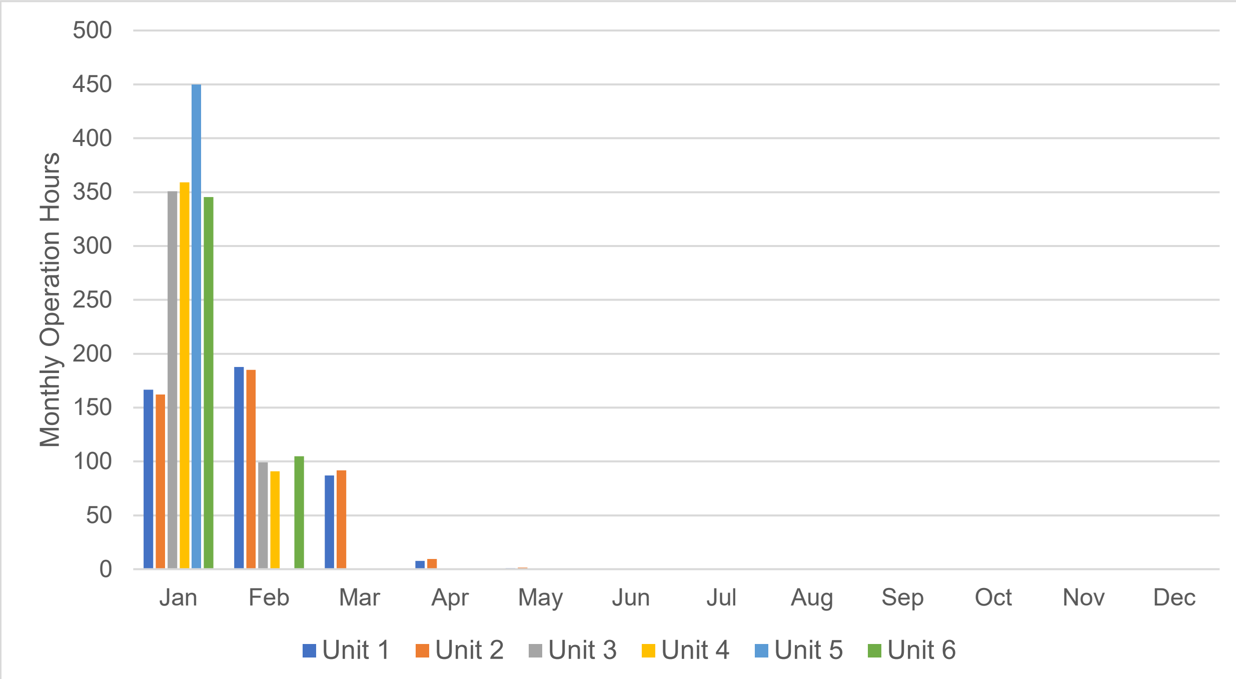


Figure 11 shows the risk of EUE is small to non-existent in the early months of the year but significantly increases towards the later months, showing a large spike in the month of December, frequently the month experiencing highest annual demand. Units that are bound by the 450-hour limitation are run in the high demand months of January and February to avoid load shed contributing to the low EUE numbers early in the year. Once the allocated hours are used up, the units are not permitted to generate further and the figures show how December, a high load month, has a significant EUE risk. The same trend is shown in Figure 12; however, the supply shortfall values are much higher given the coal-to-gas retirements in addition to the 450-hour limitation set by the CER.

Figure 13 below demonstrates the operating behavior of unabated gas assets under the CER 450-hour limitation in the year 2038. As mentioned previously, the units tend to go through their allocated hours in January and February, since they are high demand months, then mothball until the end of the year.

Figure 13. Monthly Operation Hours Under CER for Unabated Gas Units in 2038



Alternative Decarbonization

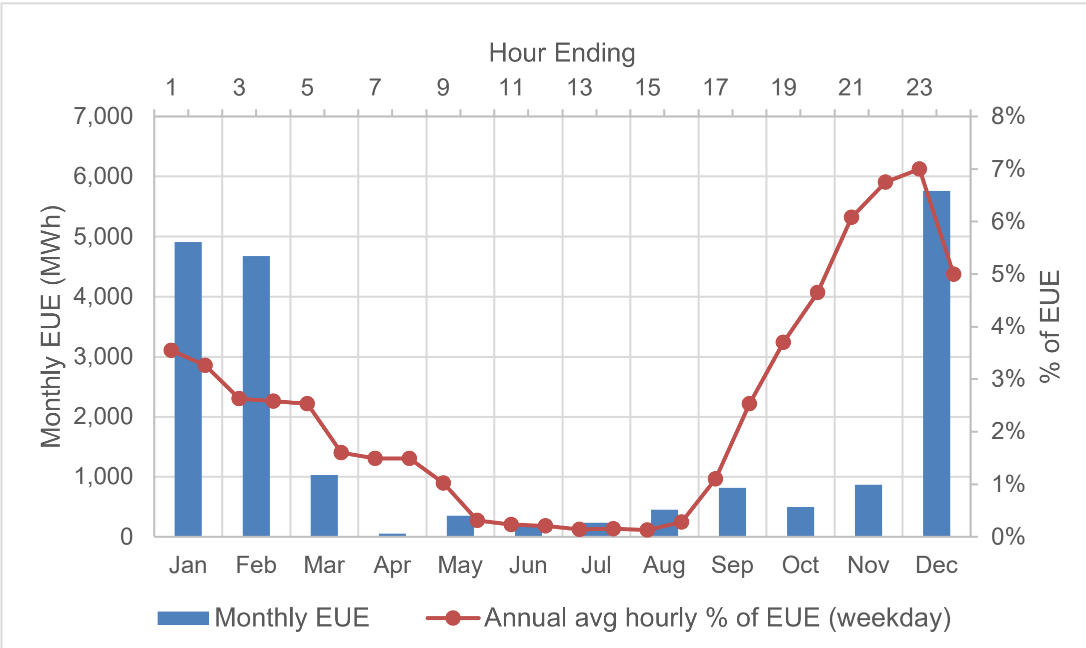
The Alternative Decarbonization scenario explores other resource mixes resulting from changing capital costs for emerging technologies, such as CCUS, battery energy storage and nuclear SMRs. In comparison to the Reference Case, the cost of CCUS technology is doubled, the expected decline in energy storage costs is doubled, the cost of nuclear SMRs is held constant instead of declining and the Alberta – British Columbia intertie is doubled to reach 2,350 MW in capability, increasing the net interchange capability with all regions to 2,800 MW.

Table 7. EUE, LOLE, and LOLH Metrics for Alternative Decarbonization by 2050

Year	EUE (MWh)	LOLE (# of days)	LOLH (hours)	EUE Threshold (MWh)
2035	7	0.03	0.03	1,133
2038	19,833	14.3	41.2	1,171

Table 7 shows the results of the Alternative Decarbonization runs. Similar to the Reference Case, year 2035 shows no EUE risk, however, the year 2038 shows significant amount of EUE risk. As mentioned above, the EUE risk in the year 2038 is largely driven by the retirements of coal-to-gas units. Moreover, the increase in the intertie was insufficient to compensate for the coal-to-gas retirements in 2038.

Figure 14: Alternative Decarbonization by 2050 Monthly and Hourly EUE Distribution for the Year 2038



As seen from Figure 14, the winter months of January, February and December are heavily at risk of EUE. Moreover, the hourly shape of EUE distribution shows HE 23 remains to be the highest risk hour due to the managed EV profiles in the load forecasts.

High Electrification

In this scenario, the AESO explores the impacts on reliability in a scenario whereby society consumes more electricity than previously anticipated, due to increased electrification of heating, transportation and industrial processes.[7] From a resource adequacy perspective, when running a higher load scenario, it is expected that more generation would be required to be available to meet that load. As seen from Table 8, the optimal resource mix is sufficient to achieve resource adequacy for the year 2035 but falls short in the year 2038.

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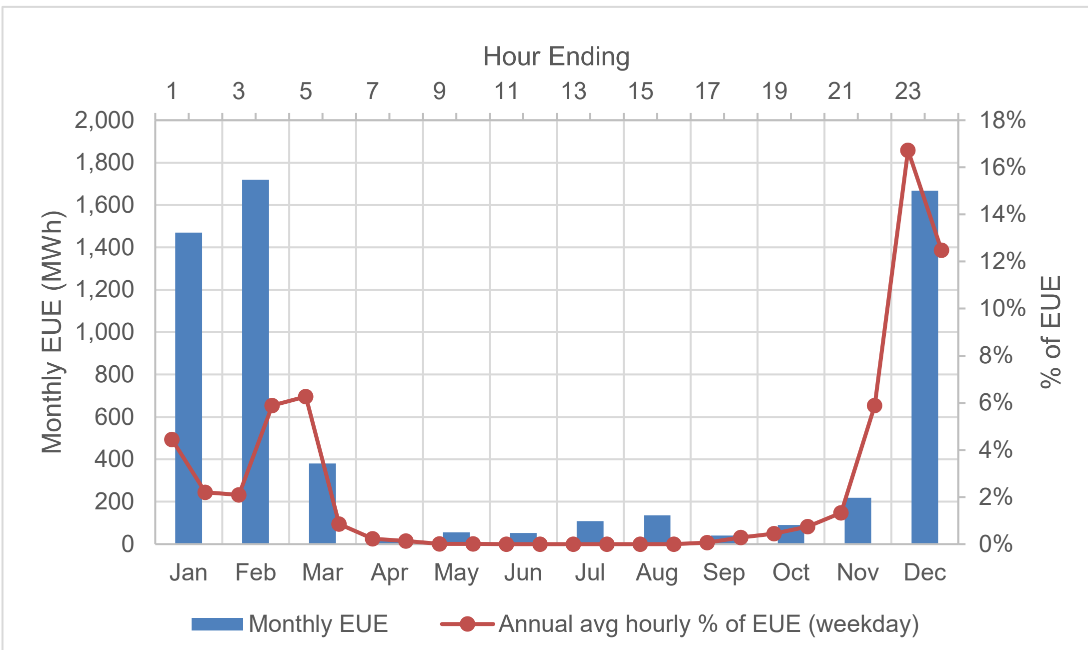
[7] For more information on the load profiles for the 2024 LTO, see the Load Methodology section.

Table 8: EUE, LOLE, and LOLH Metrics for High Electrification by 2050

Year	EUE (MWh)	LOLE (# of days)	LOLH (hours)	EUE Threshold (MWh)
2035	6	0.02	0.03	1,207
2038	5,953	7.9	14.3	1,277

As mentioned previously, the retirements of coal-to-gas assets at the end of 2037 have a major impact on supply adequacy in the province for all scenarios and all resource mixes. Although the risk of EUE in this scenario crosses the threshold for the year 2038, it is a more manageable magnitude compared to the Alternative Decarbonization and the Decarbonization by 2035 scenarios. Figure 15 shows the distribution of EUE risk throughout the year 2038. As expected, the high demand months of January, February and December pose the highest risk in the High Electrification scenario. The hourly distribution of EUE remains in line with previous scenarios with HE 23 being the highest-risk hour.

Figure 15: High Electrification by 2050 Monthly and Hourly EUE Distribution for the Year 2038



Key Results and Insights

The different scenarios analyze varying results in terms of reliability and risk of unserved energy. With the Reference Case, it is reasonable to conclude that the grid sees limited risk of unserved energy due to lack of adequate supply. The key risk to resource adequacy is the removal of coal-to-gas generation in 2037 that significantly impacts the base year of 2038. Moreover, in the Decarbonization by 2035 scenario, it is more likely the grid will experience reliability events with limited flexibility available to mitigate such risk.

1. In the Reference Case, Alternative Decarbonization and High Electrification scenarios, the generation supply forecast is expected to be sufficient to meet its adequacy standards in the 2028, 2030, 2033, 2035 and 2043 base years showing low to no risk.
2. The base year 2038 is heavily impacted due to the retirements of firm baseload coal-to-gas generation, which could be mitigated by modifying the commercialization dates of new generation.

3. Decarbonization by 2035 scenario that follows the CER limitations poses the highest risk for load shedding and unserved energy, with EUE reaching as high as 174,000 MWh mostly in high demand, winter months.

It is important to understand further electrification and decarbonization of the economy will continue to require careful monitoring of the resource adequacy implications. Reliability results for the year 2038 should be interpreted with caution. The sensitivity cases indicate resource adequacy modelling for periods further out can be significantly impacted by relatively minor changes in fundamental inputs. The 2024 LTO forecast assumptions contain significant uncertainty and thus will be monitored and appraised based on how the energy transition, technological and regulatory parameters shift over time.[8] The AESO will continue to observe, review, assess and communicate with stakeholders the implications of changes to these and other parameters, as improved information becomes available, while providing sufficient time to further mitigate risks should they become more certain.

Emissions

Emissions Calculation Methodology

Increasing policy focus on greenhouse gas emissions mitigation has prompted the AESO to analyze and publish forecast emissions levels from Alberta's electricity generation sector within the context of the 2024 LTO scenarios. Calculating electricity sector emissions is complex, as electricity generation can act as an input for other industrial activities and thus are reported under economic activities other than electricity. For example, a large amount of the generating capacity in Alberta is cogeneration, whereby natural gas is used to produce useful heat and electricity simultaneously. Many of the facilities that cogenerate electricity alongside other products or those that produce electricity as an input to other industrial production processes will account for the emissions from electricity production in their primary product of manufacture.

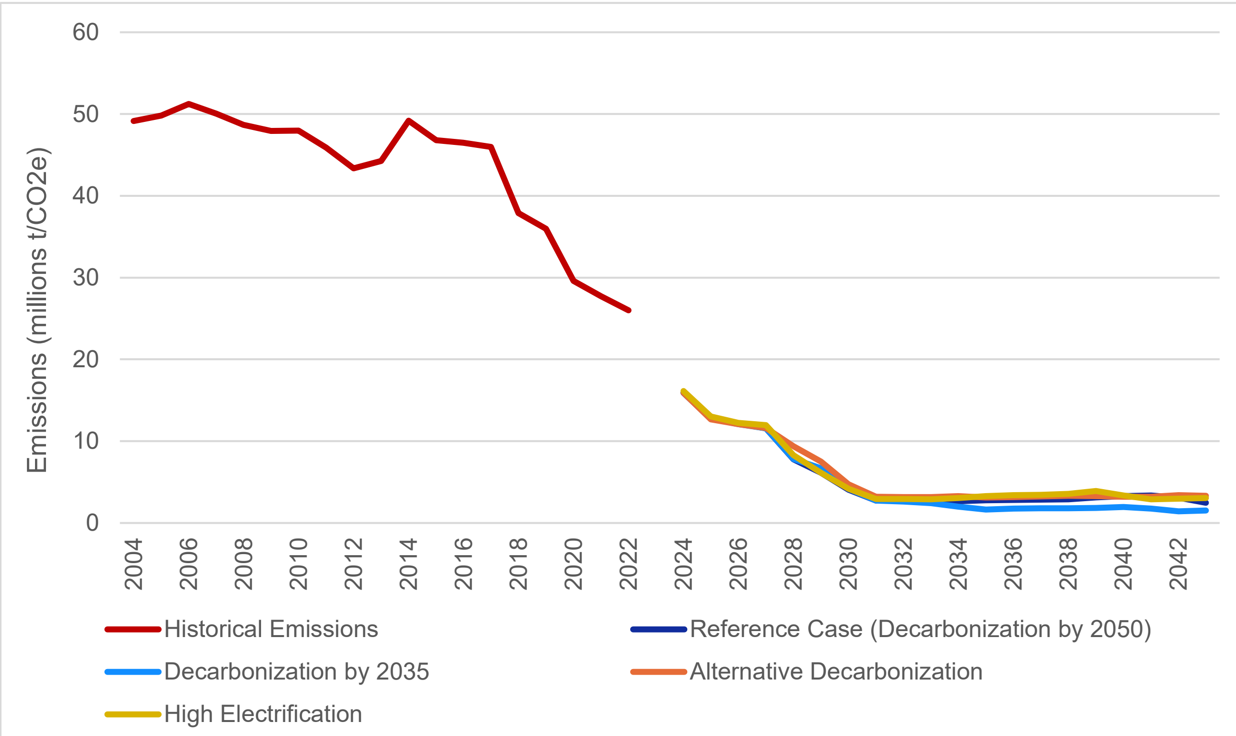
The AESO uses North American Industry Classification System (NAICS) codes to account for emissions from electricity production to avoid double counting or misrepresenting site emissions that may not be attributed to electricity. Specifically, the AESO includes facilities that report their emissions to the Government of Canada's Greenhouse Gas Reporting Program (GHGRP) under NAICS codes 221111 (hydro-electric power generation), 221112 (fossil-fuel electric power generation) and 221119 (other electric power generation). Accounting for electricity sector emissions using this methodology enables accurate comparisons of greenhouse gas emissions forecasts with historical data collected and published by the Government of Canada.

[8] For more information on uncertainties in the 2024 LTO, see the Risks and Uncertainties section.

Results

The Reference Case and each of the scenarios demonstrate a significant reduction in Alberta's electricity sector carbon emissions. This is driven by increasing policy and regulatory stringency, including an escalating carbon price, associated changes to TIER's HPB for electricity and ITCs that incent low- and non-emitting generation and CCUS.[9] By 2035, the forecast electricity sector emissions in all scenarios represent a 94 per cent to 97 per cent decline from 2005 levels (Figure 16).

Figure 16: Alberta Electricity Sector Emissions by Scenario



In each of the 2024 LTO scenarios, the majority of emissions reductions occur between 2024 and 2030 and remain relatively stable for the remainder of the forecast horizon. Between scenarios, there are only minimal differences in forecast emissions after 2030. This is largely the result of two factors: firstly, the most sweeping regulatory and policy changes occur between 2024 and 2030; the carbon price escalates to $170 per tonne, TIER's HPB for electricity tightens two per cent annually and the ITC for CCUS is at its maximum rate. These changes provide significant incentives for emissions reductions such that any CCUS retrofits on combined-cycle or cogeneration facilities occur between 2027 and 2030 in each of the 2024 LTO scenarios. At this time, it is uncertain on the timing of new CCUS projects given the May 1, 2024 statement from Capital Power that they are discontinuing their CCUS project due to not being economic albeit technically feasible. Secondly, the majority of new wind and solar facilities, including those added exogenously and those built by the long-term capacity expansion tool, come online before 2030. Within the LTO scenarios, it is expected that by 2030 Alberta will achieve its target of 30 per cent of electric energy

[9] For more information on the policy and regulatory assumptions in the 2024 LTO, see the Policy and Regulatory Drivers section.

produced to be from renewable generation sources. After 2030, remaining emissions generally arise from residual CCUS unit emissions, unabated peaking units and some unabated combined-cycle units. Under the Decarbonization by 2035 scenario, the CER limits the addition of unabated natural gas-fired units such that fewer unabated simple-cycle and no unabated combined-cycle units are built as compared to other scenarios. However, this results in an at-most reduction of 1.65 Mt per year as compared with the Reference Case.

While the greenhouse gas emissions decline is largest for the Decarbonization by 2035 scenario, the difference between scenarios is very small (Table 9). In 2035, the Decarbonization by 2035 scenario is forecast to have emissions 1.2 Mt lower than the Reference Case, while the Alternative Decarbonization and High Electrification scenarios are forecast to have slightly higher emissions than the Reference Case, 0.3 Mt and 0.5 Mt greater, respectively.

Table 9: Emissions Difference from 2005 Levels by Scenario

Scenario	2035 Emissions (million tonnes)	Emissions Difference from 2005 Levels (2035, million tonnes)	Per-cent Change (2005 to 2035)
Reference Case	2.8	-46.4	-94.39
Decarbonization by 2035	1.6	-47.5	-96.70
Alternative Decarbonization	3.1	-46.1	-93.74
High Electrification	3.3	-45.9	-93.41

Throughout the 2024 LTO timeframe, annual emissions in all scenarios differ from the Reference Case by less than two Mt annually. These differences are largely attributable to differences in the number of expected CCUS retrofits, the degree to which the intertie with British Columbia is utilized for imports, and additions of unabated natural gas-fired units. The Reference Case, Alternative Decarbonation and High Electrification scenarios forecast relatively similar supply mixes and, therefore, similar forecast emissions. As compared to the Reference Case, the Alternative Decarbonization scenario forecasts fewer CCUS retrofits but greater utilization of imports, which displaces natural gas-fired generation, while the High Electrification scenario forecasts more additions of abated combined-cycle units. The Decarbonization by 2035 scenario forecasts fewer unabated simple- and combined-cycle units than the Reference Case but sees the addition of some hydrogen-fired simple-cycle units and utilizes more imports.

Alberta Electric System Operator

2500, 330-5th Avenue SW
Calgary, AB T2P 0L4
Phone: 403-539-2450
www.aeso.ca

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