



AESO 2021 Long-term Outlook

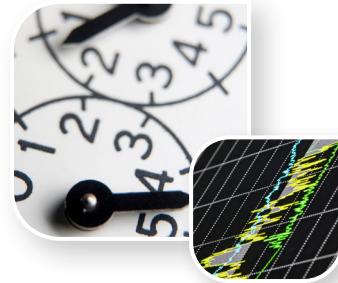
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1.0 Executive Summary



The Alberta Electric System Operator (AESO) 2021 Long-term Outlook details the expected electricity demand and anticipated generation capacity required to meet that demand over the next 20 years in Alberta.

The 2021 Long-term Outlook (2021 LTO) is the Alberta Electric System Operator's (AESO) forecast of Alberta's load and generation requirements over the next 20 years and is used as one of many inputs to guide transmission system planning, long-term adequacy assessments, and market evaluations.

Key factors that drive load growth and generation development were examined in order to understand their potential impacts in Alberta. Moderate load growth is expected over the next 20 years but at a lower rate than in the previous 20-year period. Load growth is expected in the near term due to economic recovery as COVID-19 health restrictions ease.

Generation growth is also expected in the forecast term, and natural gas is anticipated to be the primary fuel source to replace coal in the generation mix. The amount and pace of generation development is affected by technology costs, government policy, upcoming coal plant retirement decisions and profitability expectations, among other factors. Alberta's competitive electricity market drives generation investment; the 2021 LTO provides a view of what generation is expected to be developed and where it will occur.

The 2021 LTO was developed during a period of global uncertainty, and the outlook covers a period of transformation of Alberta's electricity industry. Changes in economics, government policies, technology, and the way power is produced and consumed can significantly impact load growth and development of generation. To account for these uncertainties and possible outcomes, the AESO developed a series of scenarios in addition to its main corporate outlook.

2.0

Background



The 2021 LTO serves as the foundation for the AESO's Long-term Transmission Plan, which sets out Alberta's future transmission requirements.

2.1 PURPOSE BEING SERVED BY THE AESO'S LONG-TERM OUTLOOK

The AESO's 2021 LTO describes Alberta's expected electricity demand over the next 20 years and the expected generation capacity needed to meet that demand. The 2021 LTO serves as the foundation for the AESO's *Long-term Transmission Plan*¹ (LTP), which sets out Alberta's future transmission requirements, in accordance with the Transmission Regulation.²

In addition to the LTP, the LTO is used as input into other AESO functions. These include transmission system planning studies for Needs Identification Documents (NIDs) and connection projects, the ISO tariff, and market assessments. The LTO also informs ongoing energy-only market evaluations, system flexibility and net-demand variability assessments, long-term resource adequacy analyses, policy and regulatory (including carbon emission policies) analyses, as well as other engineering and/or market reports.

The AESO continually reviews its forecasts and will, when appropriate, consider alternate load and/or generation assumptions in these other functions to align studied forecasts with the latest information.

2.2 STAKEHOLDER ENGAGEMENT

The AESO develops comprehensive forecasts using third-party information, best practices in forecasting methodology and tools, and in-house experts.

The AESO also takes time to consult with stakeholders to gather insights, validate assumptions and concerns, and understand their perspectives related to Alberta's future.

In line with the AESO's *Stakeholder Engagement Framework*, the AESO expanded interactions with and solicited feedback from stakeholders in developing the 2021 LTO. Specifically, the AESO hosted extensive engagement sessions whereby assumptions and preliminary results were presented for comment and feedback.³

¹ <https://www.aeso.ca/grid/long-term-transmission-plan/>

² The Transmission Regulation can be found here: [https://www.qp.alberta.ca/Transmission Regulation](https://www.qp.alberta.ca/Transmission%20Regulation)

³ Stakeholder consultation and responses can be found here: <https://www.aeso.ca/grid/forecasting/>

3.0 Long-term Outlook Scenarios

3.1 LONG-TERM OUTLOOK SCENARIOS

A wide range of scenarios help capture possible future states of the Alberta market and answer “what if?” questions. The 2021 LTO presents a set of four scenarios that include variations in load and generation assumptions.

TABLE 1: 2021 LTO Scenarios at a Glance

Reference Case	Scenario that tests the impact of the current policy and regulatory landscape, technological advancements and the most-predominant economic outlook for Alberta. This scenario serves as the main corporate forecast
Clean-Tech	Scenario that tests an upside to trends in decarbonization, electrification and cost reductions in renewables that accelerate grid changes toward low-emissions and greater Distributed Energy Resources (DER) technologies
Robust Global Oil and Gas Demand	Scenario that tests the impact of an aggressive growth outlook for Alberta's energy sector
Stagnant Global Oil and Gas Demand	Scenario that tests the impact of economic stagnation in Alberta due to muted investment in the oil and gas sector

Although these scenarios test assumptions and uncertainties that represent paths to an increasingly decarbonized grid in Alberta, the 2021 LTO should not be interpreted as a roadmap to a future of net-zero emissions by 2050. Rather, the 2021 LTO represents a 20-year outlook where elements that may contribute to net-zero goals are considered without an explicit target for emissions or timelines being set. The AESO will continue to assess and analyze prevalent trends that influence the transformation of the electricity sector, including releasing analyses on new technologies such as low-emissions supply types (e.g., small nuclear reactors, geothermal, hydrogen combined with carbon capture, utilization and storage) and their potential impact to the Alberta grid.

3.2 KEY DRIVERS AND ASSUMPTIONS

The 2021 LTO illustrates the desired impact of the scenarios by modifying the following three broad groups of drivers and assumptions; economy, policy, and technology.

3.2.1 Economic Drivers and Assumptions

3.2.1.1 Oil Sands Production

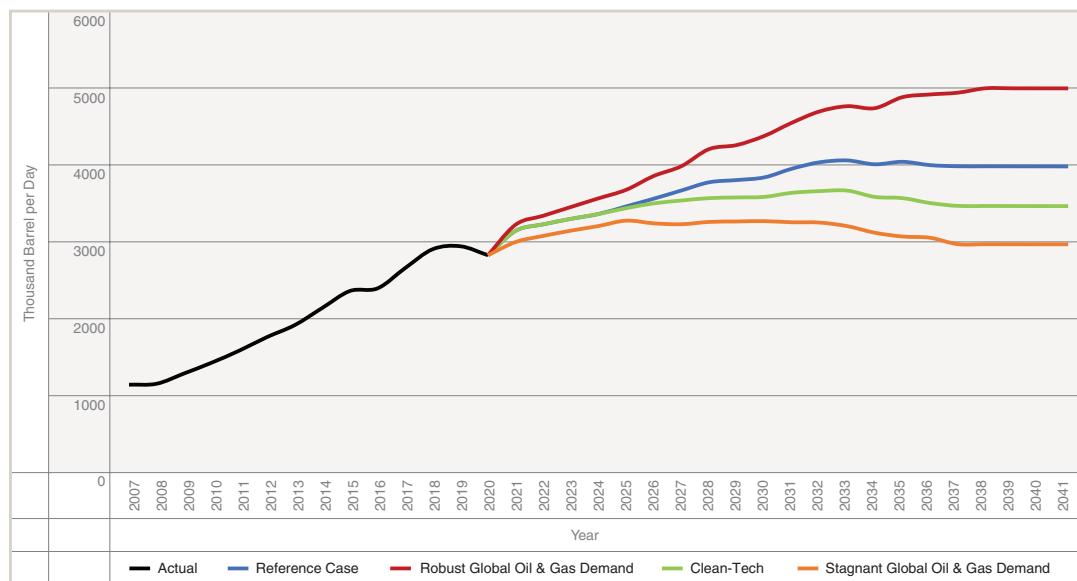
Alberta's load growth is largely dependent on energy sector investment and production. Oil sands raw bitumen production is influential throughout Alberta's economy, and correlates strongly with industrial load growth. The 2021 LTO is based on IHS Markit's Q3 2020 Alberta bitumen forecast as the indicator for long-term oil sands production outlook.

In the Reference Case, the oil sands outlook reflects the impact of the decrease in demand for oil resulting from the COVID-19 pandemic and projects a recovery to 2019 levels in 2021-2022. Following the recovery, growth is anticipated to be moderate, as projects that are on hold, where some initial work has occurred, will be completed and further optimization measures can be realized. The oil sands outlook also assumes a moderate amount of expansion and greenfield projects around 2030.⁴

The oil sands outlook is modified for every scenario by assuming different growth levels:

- The Clean-Tech scenario assumes a future driven by decarbonization efforts will lower longer term energy demand and reduce oil sands production compared to the Reference Case by approximately 13 per cent by 2040
- The Robust Global Oil and Gas Demand scenario is based on an oil sands outlook that is 25 per cent higher than the Reference Case by 2040
- The Stagnant Global Oil and Gas Demand scenario is based on an oil sands outlook that is 25 per cent lower than the Reference Case by 2040

FIGURE 1: Oil Sands Production Outlook by Scenario



⁴ A summary of the IHS Markit oil sands outlook can be found here: <https://ihsmarkit.com/research-analysis/longer-term-outlook-for-canadian-oil-sands.html>.

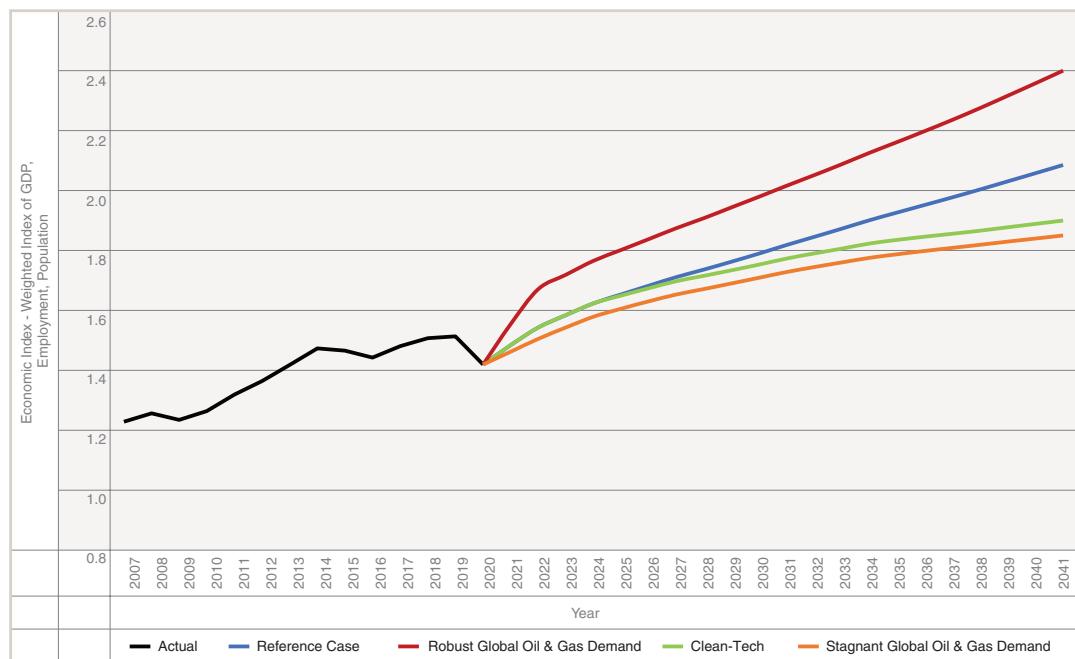
3.2.1.2 Economic Recovery

The 2021 LTO economic indicators are represented by a composite index, based on a weighted average of real Alberta gross domestic product (GDP), employment and population estimates, that is adjusted for energy efficiency. The economic variables are sourced from the Conference Board of Canada's (CBoC) provincial economic outlook. The 2021 LTO combines the CBoC's five-year forecast, which represents the medium-term (2020 through 2024) impact of the COVID-19 pandemic and activities in the energy sector, with the CBoC's long-term growth drivers published in its 20-year provincial economic outlook from 2025 onwards.⁵ The three economic variables are weighted based on their correlation with average annual Alberta Internal Load (AIL) from 2015 to 2019. For the Edmonton and Calgary planning regions, the economic variables are based on the CBoC's metropolitan economic forecast reports respectively⁶, which help capture specific trends from those regions. The energy efficiency assumption is derived using historic energy efficiency gains in Alberta and is intended to capture expectations of energy efficiency improvements within the province.

The 2021 LTO Reference Case anticipates a near-term boost to economic growth in 2021 and 2022, followed by normalized growth through 2041. Though the COVID-19 pandemic and decline in oil production in Alberta caused a significant contraction in GDP and employment levels in 2020, a strong rebound is forecast in the near term. The longer-term forecast exhibits a return to a modest pre-pandemic economic growth.

For the other scenarios, alternative economic indices are applied to capture the relationship between differing oil sands production outlooks (described above) and overall economic impact in the province.

FIGURE 2: Economic Index by Scenario



⁵ CBoC (2020), Uneven Recovery: Provincial Outlook, <https://www.conferenceboard.ca/e-library/abstract.aspx?did=10785>; CBoC (2019), Provincial Outlook Long-Term Economic Forecast: 2019, <https://www.conferenceboard.ca/e-library/abstract.aspx?did=10089>

⁶ CBoC (2020), Major City Insights: Edmonton—Autumn 2020, <https://www.conferenceboard.ca/e-library/abstract.aspx?did=10840>; CBoC (2020), Major City Insights: Calgary—Autumn 2020, <https://www.conferenceboard.ca/e-library/abstract.aspx?did=10839>

3.2.1.3 Cogeneration

The 2021 LTO reflects growth in cogeneration capacity, as industrial and oil sands activity continues to recover. Cogeneration has been implemented in many diverse applications throughout Alberta, with prominence in oil sands production. Steam-assisted gravity drainage (SAGD) and cyclic-steam stimulation (CSS) recovery techniques often include cogeneration facilities that provide the steam and electrical needs of the oil sands operations, while enabling the export of electricity to the grid in a highly efficient manner. The existing provincial carbon regulations provide incentive to efficient forms of generation, and the 2021 LTO reflects expected cogeneration growth stemming from oil sands activity. The Technology Innovation and Emissions Reduction (TIER) regulation provides incentives for high-efficiency cogeneration units that are expected to improve the economics of the technology for greenfield and brownfield applications.⁷

Cogeneration capacity, including projects that meet the AESO connection process inclusion criteria (see Section 5.1.4), in each scenario totals:

- 6,669 MW by 2041 in the Reference Case
- 6,804 MW by 2041 in Clean-Tech scenario
- 7,659 MW by 2041 in the Robust Global Oil and Gas Demand scenario
- 5,994 MW by 2041 in the Stagnant Oil and Gas Demand scenario

3.2.1.4 COVID-19 Pandemic

The 2021 LTO is being released at a time of significant global uncertainty. Domestic production and energy consumption have been particularly impacted by public health measures which have restricted most economic and social activities. The global pandemic resulted in lower energy demand and reduced oil prices in 2020 – directly impacting Alberta-based conventional oil and oil sands sectors, which led to declines in AIL in 2020. The combined impact of the pandemic and low oil prices led to significant declines in load in 2020. At its lowest point in 2020, AIL declined between five and eight per cent (400 MW to 800 MW) from 2019 load on a normalized basis.⁸ Although demand has recovered substantially, the world remains in a state of caution, as COVID-19 vaccines are distributed and restrictions are lifted.

Throughout 2020, the AESO provided ongoing updates on the impact on load from the pandemic and low oil prices. The 2021 LTO incorporates these impacts into the modelling and assumes post-pandemic recovery by 2022.

The pandemic-related assumptions are the same for all scenarios.

3.2.2 Policy Drivers and Assumptions

3.2.2.1 Carbon Policy

A trend towards sustainable, decarbonized economies has increased the adoption of carbon policies throughout the developed world. Carbon policy has been transformational to Alberta's electricity generation fleet and will continue to influence the economics of generating units. Indeed, carbon emissions taxes are increasingly the highest variable cost for many fossil-fuel generators in the province. Conversely, existing regulations provide incentives to renewable and low-emitting generators. Given the impact that carbon regulations will have on the future outcome of the electrical system, it is important to consider the evolution of regulation as a foundation for the forecast.

⁷ <https://www.alberta.ca/technology-innovation-and-emissions-reduction-regulation.aspx>

⁸ More details on the load declines in 2020 can be found in the AESO's 2020 Annual Market Statistics: <https://www.aeso.ca/assets/Uploads/2020-Annual-Market-Stats-Final.pdf>

Alberta has had a tax on large emitters over the past 15 years that has increased as a result of more stringent regulations being enacted. Starting in 2007, the Alberta government legislated the Specified Gas Emitters Regulation (SGER)⁹, which priced carbon dioxide and equivalents (CO₂e) emissions at \$15-per-tonne and imposed requirements on regulated emitters to reduce their emissions by 12 per cent compared to their baseline conditions. In 2016, the Alberta government increased the price on emissions to \$20-per-tonne and increased the required reduction to 20 per cent. In 2017, the price was increased to \$30-per-tonne.

In 2018, the SGER was replaced with the Carbon Competitiveness Incentive Regulation (CCIR).¹⁰ CCIR retained the 2017 carbon emissions price while further strengthening the emissions targets of power plants to reflect “best-in-class” combined-cycle technology. A baseline emissions level of 0.37 tonnes CO₂e-per-megawatt-hour was applied to all electricity generators, effectively imposing more stringent compliance measures than SGER on coal and inefficient gas generators, while easing compliance measures on the most efficient combined-cycle generators. In 2020, the Alberta government replaced CCIR with the TIER, which held the electricity industry to the same 0.37 tonne-per-megawatt-hour standard. The carbon price was held constant at \$30-per-tonne to maintain equivalency with the federal government’s federal Greenhouse Gas Pollution Pricing Act.¹¹ In January 2021, the federal government increased the carbon price to \$40-per-tonne, and the provincial carbon price followed, per Ministerial Order 36/2020.¹² The Government of Alberta has announced its intention to raise the carbon price to \$50-per-tonne in 2022, following guidance from the Greenhouse Gas Pollution Pricing Act.¹³ As of the time of the 2021 LTO writing, there was no legislated federal carbon price extending beyond 2022, despite a December 2020 announcement from the federal government proposing an increase in carbon prices by \$15-per-tonne per year to \$170-per-tonne by 2030.

In addition to the Greenhouse Gas Pollution Pricing Act, the Government of Canada is in the process of implementing Clean Fuel Regulations¹⁴, often referred to as a clean fuel standard (CFS). The CFS will come into effect as of January 2022 and will require suppliers of liquid fuels to reduce the carbon-intensity of their fuels. Previously, the Government of Canada had announced CFS for gaseous and solid fuels as well, but subsequent to the announcement of the \$170-per-tonne carbon price in 2030, plans for gaseous and solid CFS were abandoned. The CFS for liquid fuels is not expected to have a major impact on power generation in Alberta but may influence renewables generation and energy efficiency projects at fuel production sites.

The 2021 LTO assumes a \$40-per-tonne carbon price in 2021, increasing to \$50-per-tonne in 2022, and then increasing at an inflationary rate thereafter for the Reference Case. The same carbon price forecast is used in the Robust Global Oil and Gas Demand scenario and the Stagnant Global Oil and Gas Demand scenario. The carbon price schedule is modified for the Clean-Tech scenario by adopting the federally announced \$170-per-tonne carbon price by 2030, increasing at an inflationary rate through the remainder of the forecast horizon.

⁹ <https://www.alberta.ca/specified-gas-reporting-regulation.aspx>

¹⁰ <https://www.alberta.ca/carbon-competitiveness-incentive-regulation.aspx>

¹¹ <https://laws-lois.justice.gc.ca/eng/acts/G-11.55/>

¹² <https://open.alberta.ca/publications/aep-ministerial-order-36-2020>

¹³ <https://www.alberta.ca/assets/documents/ep-tier-conventional-oil-and-gas-session.pdf>

¹⁴ <https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard.html>

3.2.2.2 Corporate Power Purchase Agreements

As renewable technology costs continue to decline, opportunities for organizations to decrease their carbon footprint have become more economic and more attractive. Wind and solar technologies present options for corporations to meet sustainability objectives at a reasonable incremental cost to market-priced power. As these technologies advance, costs are expected to decline further, and more organizations are anticipated to contract some portion of their electricity needs from renewable electricity projects, contributing to the increase in renewables development in Alberta. The competitive electricity market structure in Alberta makes the province a primary candidate for locating corporate power purchase agreement (PPA) backed assets, compared to other provinces.

The 2021 LTO Reference Case anticipates 1,280 MW of renewable capacity driven by corporate PPAs by 2041. This corporate PPA capacity is in addition to the volumes associated with the Renewable Electricity Program (REP), volumes added based on near-term project inclusion criteria and volumes added based on merchant economics. The Clean-Tech scenario expects 2,830 MW of renewable corporate PPAs, the Robust Global Oil and Gas Demand scenarios forecasts 1,330 MW of renewable corporate PPAs and Stagnant Global Oil and Gas scenario forecasts 550 MW. In addition there are approximately 200 MW of near-term projects included in all scenarios that have partial or full corporate PPAs associated with them.

3.2.3 Technology Drivers and Assumptions

3.2.3.1 Distributed Energy Resources

Distributed Energy Resources (DER) are playing an increasing role in meeting Albertans' electricity needs. As explained in the AESO's *DER Roadmap*, this type of technology includes any distribution-connected resources that can potentially supply energy onto the interconnected electric system, and includes installation at sites with demand as well as independent generation developments connecting to the distribution system.¹⁵ Starting in 2020, the AESO has published regular reports on the penetration of small-sized (less than five MW) DER, making a distinction between those that qualify under the Micro-generation Regulation.^{16,17}

The 2021 LTO includes projections of different classes and sizes of DER, each modelled based on unique drivers and assumptions as explained in Table 2.

TABLE 2: DER Forecast Assumptions

	Less than 5 MW Maximum Capability (MC)	Equal or greater than 5 MW MC
Solar Generation	Roof-top solar panels are driven by declining capital and installation costs for photovoltaic (PV) panel cells, government incentives, and increasing consumer adoption rates across Alberta urban centres	As explained in the Policy drivers section, the outlook for these types of renewable resources is influenced by carbon policies and increased uptakes in corporate PPAs
Wind Generation	Small scale wind generation is expected to increase during the forecast period. Modest amounts of wind distributed energy resources are anticipated due to the required mutual location of advantageous connection nodes, suitable wind resources, and acceptable environmental permitting	
Gas-fired Generation	To the extent that the grid-delivered cost of electricity increases through the forecast term relative to the costs of self-generation, it is expected that additional opportunities for distributed on-site gas-fired generation may grow depending on various factors such as wholesale electricity prices and carbon taxes	

¹⁵ To learn more about the AESO's DER Roadmap, check here: <https://www.aeso.ca/grid/grid-related-initiatives/distributed-energy-resources/>

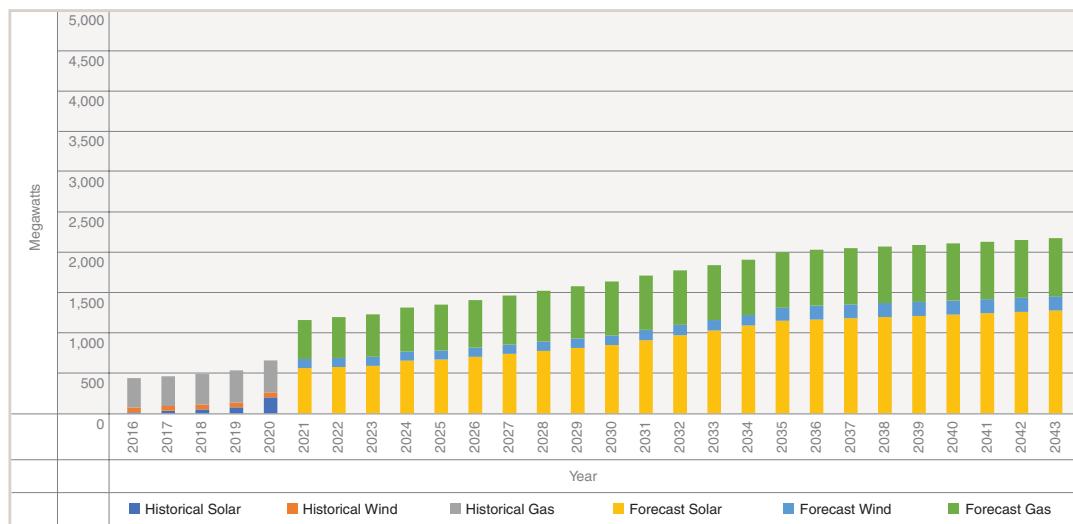
¹⁶ To access the AESO's Micro- and Small-Distributed Generation reports, check here: [https://www.aeso.ca/index.php/market/market-and-system-reporting/micro-and-small-distributed-generation-reporting/](https://www.aeso.ca/index.php/market-market-and-system-reporting/micro-and-small-distributed-generation-reporting/)

¹⁷ For more details on Micro-generation eligibility, check here: <https://www.alberta.ca/micro-generation.aspx>

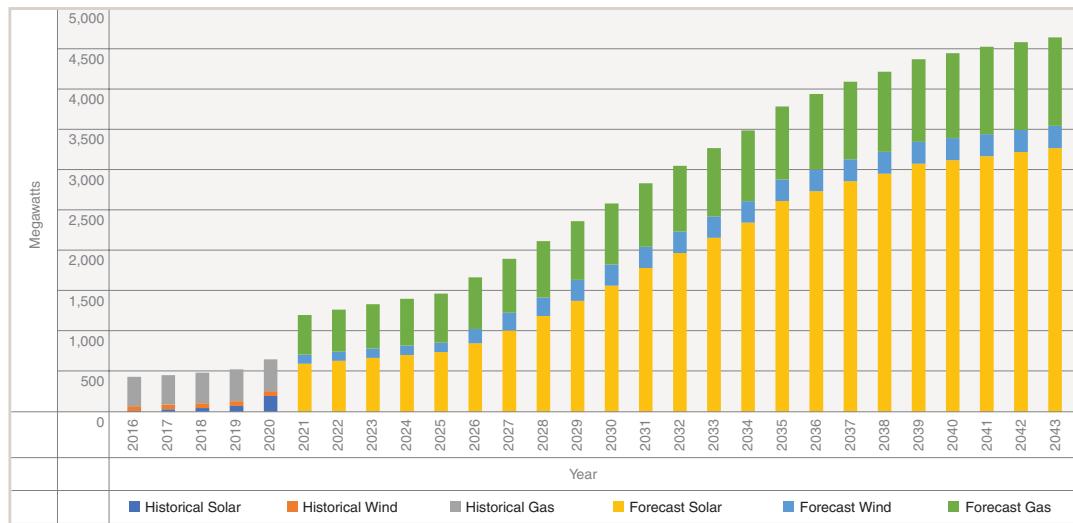
The 2021 LTO includes two DER penetration outlooks. The Reference Case, the Robust Global Oil and Gas Demand scenario and the Stagnant Global Oil and Gas Demand scenario share the same DER outlook, which is based on current expectations of trends and economics. The Clean-Tech scenario tests more aggressive penetration levels due to a combination of factors such as reduced capital costs, incentivizing policy actions and increased consumer preferences toward decentralized sources of energy.

FIGURE 3: Assumed Installed Capacity of DER¹⁸

DER Outlook for the Reference Case, Robust Global Oil and Gas Demand Scenario and Stagnant Global Oil and Gas Demand Scenario



DER Outlook for the Clean-Tech Scenario



¹⁸ These charts do not include other types of DER, such as biomass, hydro or energy storage.

3.2.3.2 Electric Vehicles

Electric vehicle (EVs) options present motorists with an alternative to fossil-fuel powered transportation. Adoption of electric vehicles depends on the comparative costs versus internal-combustion engine vehicles, consumer preferences and trends, policy and program incentives, charging infrastructure availability and affordability, and the impact of weather conditions on a vehicle's performance. For the purposes of the 2021 LTO, EVs are modelled as a load-only resource (i.e., only in charging mode) and there is no treatment for vehicle-to-grid technology. Although vehicle-to-grid configurations¹⁹ may bring potential benefit to system planning and operations, the 2021 LTO assumes this type of technology will have very limited impact in Alberta over the forecast period. Vehicle-to-grid technology is currently in a state of infancy, and the benefits to customers, retailers and the grid are currently too limited to be considered economically viable.

The Reference Case includes growth in electric vehicle sales and use in the province that will translate into approximately 120 MW of average demand growth and nearly 400 MW of peak demand growth by 2040. The Clean-Tech scenario tests a more aggressive adoption rate, whereby electric vehicles represent over 30 per cent of the total stock of Alberta vehicles by 2040. The Clean-Tech scenario results in 1,185 MW of average demand growth and slightly over 3,900 MW of peak demand growth attributable to electric vehicle charging profiles. For reference, the assumed number of electric vehicles is estimated to be 14,000 in 2021, and by 2041 is forecast to reach up to 195,000 vehicles in the Reference Case and 1,960,000 vehicles in the Clean-Tech scenario. The assumptions used for the Reference Case are maintained for the Robust Global Oil and Gas Demand scenario and the Stagnant Global Oil and Gas Demand scenario.

FIGURE 4: Assumed Number of Electric Vehicles in Alberta

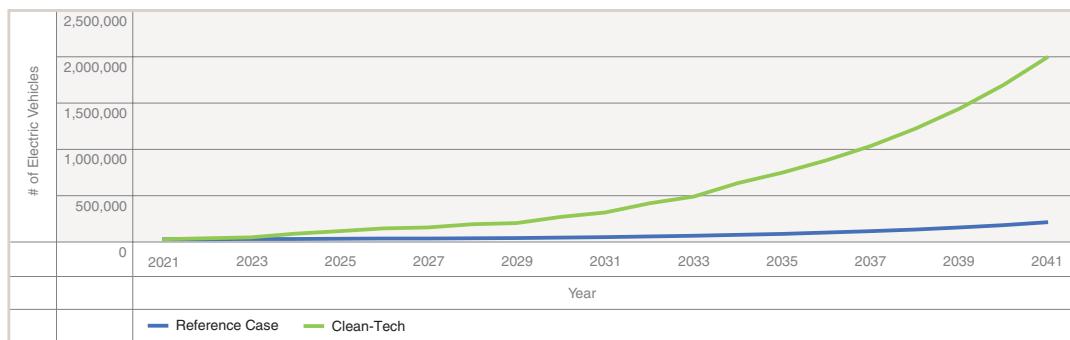
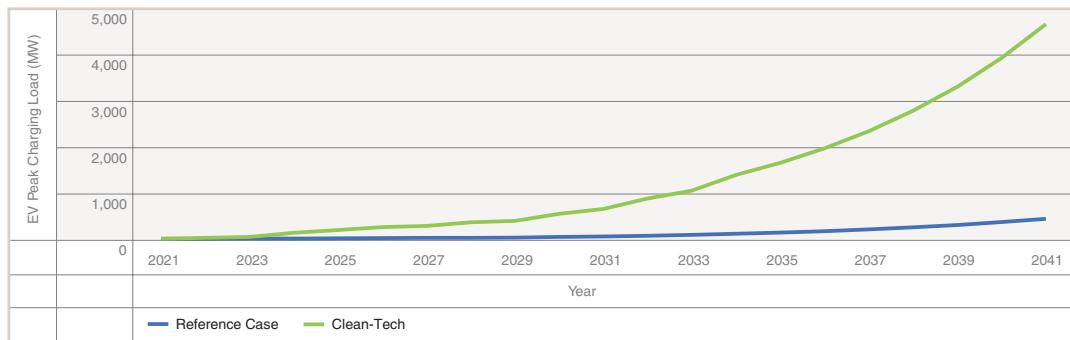


FIGURE 5: Incremental Peak Load Attributed to Electric Vehicles



¹⁹ Vehicle to grid technologies enable energy stored in electric vehicle batteries to be supplied to the power grid. With vehicle-to-grid technology, a car battery can be charged and discharged based on different signals — such as energy prices, transmission and distribution delivery charges, or need to balance variations in energy production and consumption.

Although the increased penetration of EVs and their corresponding impact on peak load may suggest potential stress on Alberta's electric grid, these 2021 LTO assumptions are meant to represent an upper-bound to inform ongoing operational and planning studies. The 2021 LTO provides further analysis and sensitivities of EV charging profiles in Section 5.1 Additional Insights.

3.2.3.3 Energy Storage

Energy storage technologies have gained momentum in Alberta and are expected to continue to contribute to the operation of the power grid into the future. At present, battery technology is improving both in terms of performance and cost. With significant global resources directed at EV technology research and development, battery storage technologies are anticipated to progress in the forecast horizon. Applications of battery energy storage systems, either as stand-alone facilities or combined with other generation technologies, include ancillary service operating reserve provision, energy arbitrage, and unique energy services. Technological advancement is expected to be the largest driver in battery energy storage growth in Alberta. Although other forms of energy storage have advanced in other jurisdictions, economic opportunities for such technologies are expected to remain modest in the Reference Case.

The AESO *Energy Storage Roadmap*²⁰ was developed in 2019 to facilitate integration of energy storage technologies into the electricity system framework on an impartial basis. *The Energy Storage Roadmap* sets out the AESO's plan to facilitate the reliable integration of energy storage technologies into AESO authoritative documents and the AESO grid and market systems.

The 2021 LTO Reference Case incorporates 150 MW of energy storage capacity in the forecast by 2041, consisting of battery technologies and some hybrid units. The same energy storage assumptions are applied to the Robust and Stagnant Global Oil and Gas Demand scenarios, while the Clean-Tech scenario forecasts 1,520 MW of energy storage, including 75 MW of pumped-hydro energy storage.

3.2.4 Risks and Uncertainties

The 2021 LTO was developed during a period of uncertainty for Alberta's electricity industry. Continuing evolution of carbon policy, the global COVID-19 pandemic and economic challenges have created a very fluid situation for the Alberta electricity sector. The primary drivers of historical load growth in Alberta have been subjected to significant headwinds. The oil sector was severely impacted by the demand destruction resulting from the COVID-19 pandemic, and although oil prices have substantially recovered, new investment remains apprehensive. Policy changes in Canada and the United States have meant that several key projects have either been cancelled or their future has been called into question. These headwinds, paired with increasingly stringent carbon policies and a global pandemic, have created an environment of heightened uncertainty for electricity forecasting.

Increasingly stringent carbon policy and technological advancement continue to drive change within the electricity landscape, both in terms of how producers generate electricity and how consumers use electricity. The impact of provincial and federal greenhouse gas policy will shape the pace at which carbon intensive technologies retire and the rate at which lower carbon generation sources displace them. Coal-powered generation facilities are in the process of transforming to cleaner fuel sources, reflecting the impact of increased emissions costs on their profitability. Conversely, renewable generation developments have surged, and highly efficient generation sources continue to benefit from credits monetized outside of the electricity market. The impact of carbon policy has changed the electricity landscape in Alberta and is expected to continue to be a key driver

²⁰ <https://www.aeso.ca/assets/Uploads/Energy-Storage-Roadmap-Report.pdf>

of investment decisions in the province's electricity generation mix, as carbon prices escalate. Technologies such as hydrogen fuel and carbon capture and storage may allow thermal assets to reduce their emissions impact in the future, but at present their economics remain challenging.

Electrification of transportation is another significant source of uncertainty within the LTO forecast horizon. Increasing EV penetration has the potential to add significant demand to and reliance on the electric system. The rate of EV adoption will depend on the competitiveness of EVs vis-à-vis fossil fuel-based transportation or other alternative transportation technologies, including vehicles powered by hydrogen. As such, technological advancement and cost reductions in battery technology will be paramount in dictating the electrical load serving the transportation sector. Uncertainty regarding the pace of technological advancement and the potential for cost reductions in electric vehicles creates difficulty in forecasting EV adoption rates. Meanwhile, carbon policy will continue to provide cost pressure on internal combustion vehicles during this time. The inflection point at which EVs become competitive will depend on these factors and will dictate the speed at which they substitute fossil fuel technologies.

Various supply, demand, technological and regulatory uncertainties will shape the ongoing transformation of the electricity industry. The pace of technological adoption and changing regulations impact electricity supply and demand, but also impact Alberta's economy more broadly. These variables are inherently difficult to forecast and represent material uncertainties to the 2021 LTO. The AESO remains committed to monitoring these trends and assessing signposts in consultation with stakeholders to ensure the long-term assessments of Alberta market fundamentals account for these uncertainties.

3.3 FORECAST METHODOLOGIES

3.3.1 Project Inclusion Criteria

Specific projects that are included in 2021 LTO must reach a threshold set out by the AESO Connection Process project inclusion criteria. Project inclusion occurs under the following circumstances:

- For connection projects
 - A System Access Service (SAS) contract is effective or,
 - Permit and License has been issued (if there is no SAS)
- For behind-the-fence (BTF) projects
 - An SAS contract is effective or,
 - Generating Unit Owners Contribution (GUOC) has been paid (if there is no SAS) or,
 - Gate 3/4 has been passed (if there is no GUOC)
- For contract change projects
 - An SAS contract is effective

This methodology applies to load and generation projects.

3.3.2 Load Forecasting Methodology

Energy consumption in Alberta can be represented and calculated via different measures. In the case of the 2021 LTO, the key representative measure of consumption is Alberta internal load (AIL) which accounts for load that is served by grid-connected generation and distribution-connected generation (equal or greater than five MW), load served by behind-the-fence (BTF) generation, and load from Medicine Hat.

The 2021 LTO models AIL using load forecasting software that produces hourly load projections 20 years into the future. The modeling is performed across different load hierarchies — AIL, planning regions, areas and every individual point of delivery (POD) — by quantifying the relationship between historical load and input variables such as real GDP, population, employment, oil sands production, gas production, meteorological inputs, calendar variables and key load-impacting events (e.g., 2016 Fort McMurray wildfires, COVID-19 pandemic). The training dataset generally covers a five-year period — January 2015 through July 2020.

Different econometric models were applied to forecast the load at different hierarchy levels. Each model was specified individually, and when required, model-specific binary variables were employed to capture outages, hourly profile changes, inter-POD transfers and anomalies such as non-weather/seasonality sensitive factors.

New or expansion projects were also incorporated into the appropriate hierarchy model, particularly if these projects had a high probability of materializing or have met the inclusion criteria described above. Exceptions were made on a case-by-case basis based on regulatory hurdles and whether the project is an expansion to an existing site.

The last step to finalize the load forecast was to incorporate energy output from DER and charging load from electric vehicles.

3.3.3 Generation Forecasting Methodology

The AESO's generation addition and retirement forecasting begins with existing projects and specific near-term projects that have reached the project inclusion criteria described above in Section 3.3.1. Next, the AESO layers on longer-term facilities that are expected to develop based on corporate PPAs, or drivers that are primarily exogenous to the electricity market, such as cogeneration.

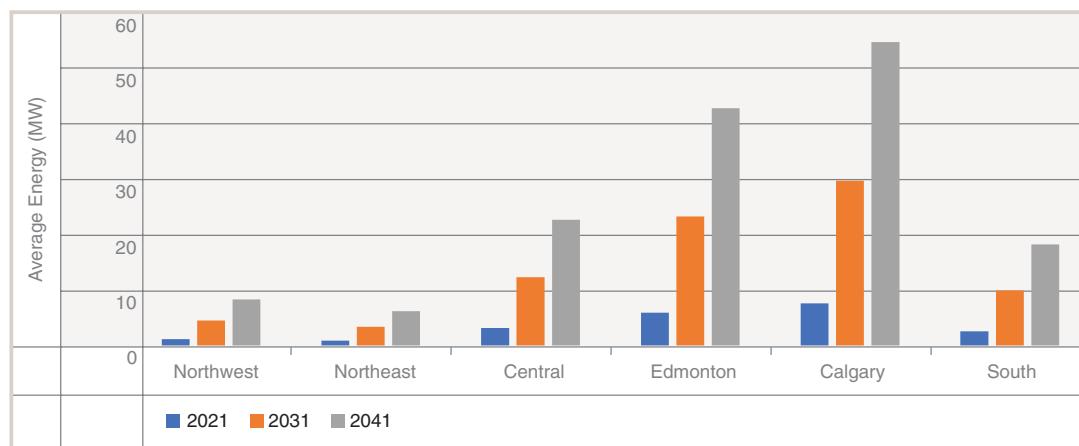
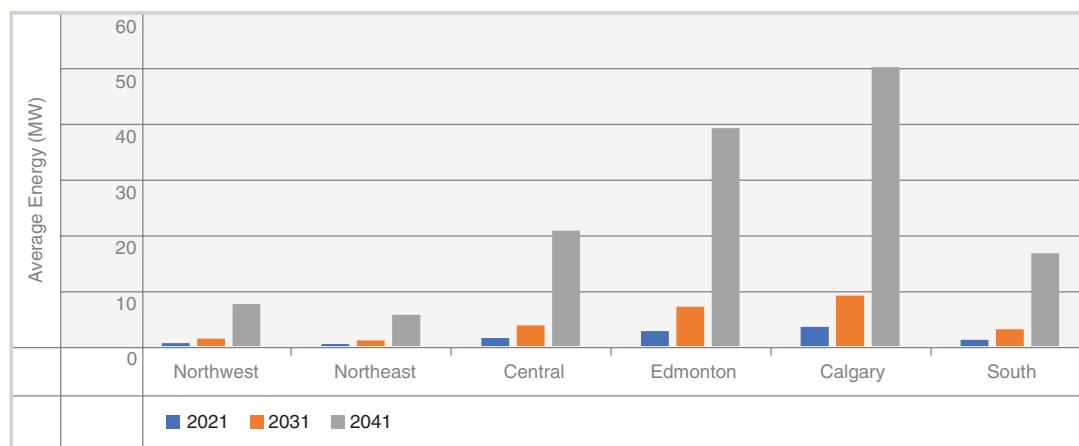
Generic generation additions represent units that are forecast to come online in the medium and long-term and are not associated with any specific projects. Opportunities for new generation development are driven by increasing load (predominantly in the oil and gas sector), retirements of existing generating assets, decreasing capital costs for renewables and storage, and corporate PPAs for renewables. Generic combined-cycle, simple-cycle, wind, and solar projects are added to the market on an economic basis through iterative addition of projects, weighing supply and demand fundamentals and expected economic returns. Only those generic units which meet an economic hurdle rate are ultimately added to the AESO's supply forecast. The economic addition of assets is a shift in generation forecasting methodology from previous LTOs that also relied on reserve margin targets as a build signal. Cogeneration additions, conversion of existing assets and non-merchant renewable projects (corporate PPAs) are added exogenously based on trends and market information related to those technologies.

3.3.4 DER Forecasting Methodology

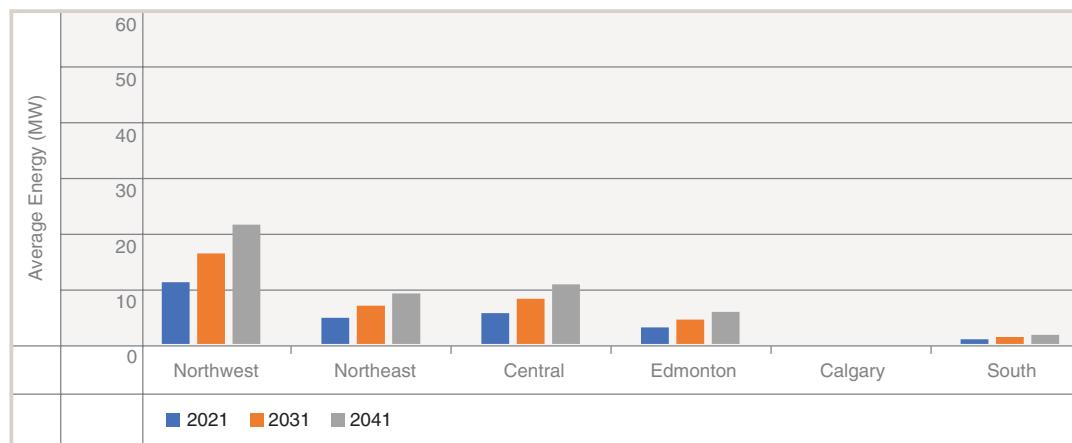
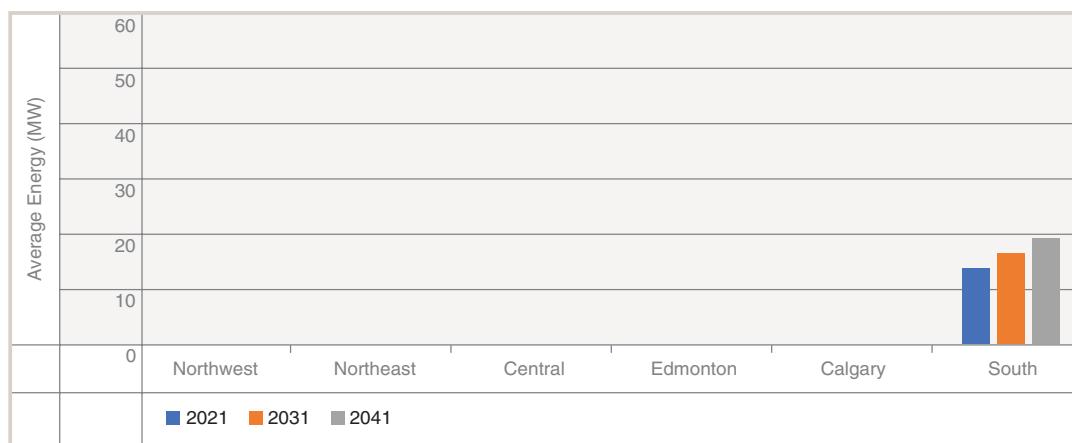
The 2021 LTO forecast for DER is based on the five MW threshold. DER less than five MW are forecast based on the historical trend of offset load. The greater than or equal to five MW DER are forecast based on the generation forecast methodology described above. The forecast leverages multiple pieces of analysis and research to develop a chosen energy profile and POD allocation for every DER technology.

TABLE 3: DER Energy and Geographical Assumptions

	Energy Profile	Geographical Allocation
Solar Generation	Weather synchronized profiles are the same as load weather years (2011 winter months and 2003 summer months ²¹⁾)	Based on population proportion of mid- and large-sized urban centres – this methodology is also applied to the allocation of EVs across the province
Wind Generation		Predominant in wind-rich planning areas
Gas-fired Generation	Based on historical metered generation and MC	Assigned to industrial areas where potential for growth is prevalent

FIGURE 6: Sub-5 MW DER Allocation by Planning Region in the Reference Case**Solar DER (less than 5 MW)****Electric Vehicle**

²¹ Winter months are January to April and November to December; summer months are May to October.

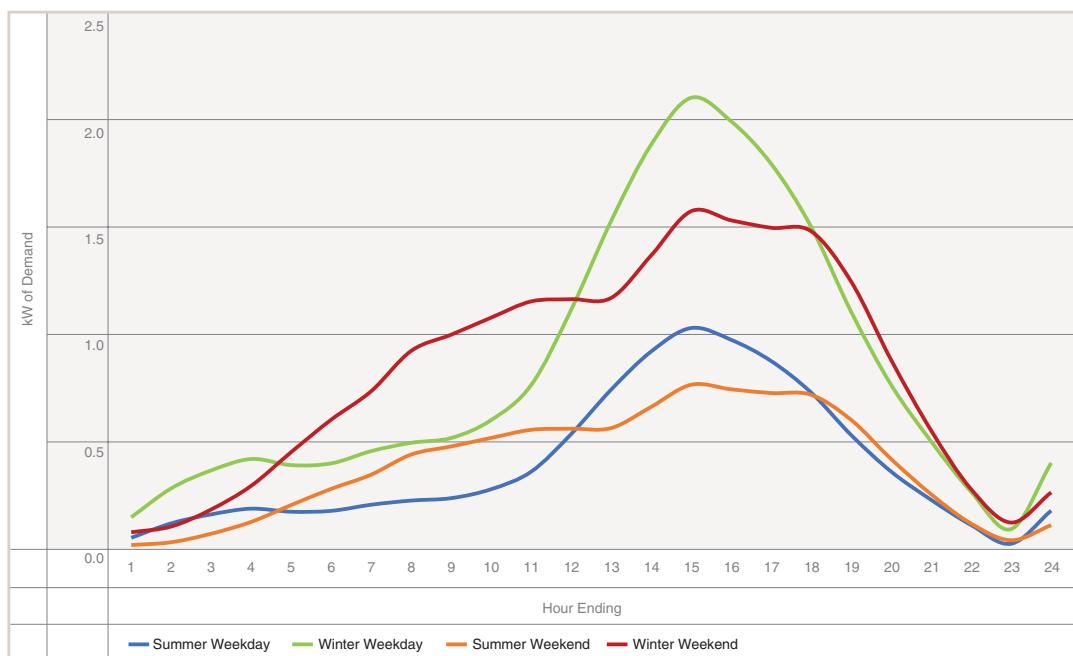
Gas DER (less than 5 MW)**Wind DER (less than 5 MW)**

3.3.5 Electric Vehicle Forecasting Methodology

Although technological advances may enable aggregation of electric vehicles and the participation of aggregated EVs as vehicle-to-grid resources into the electricity market, such applications remain in nascent stages and have not yet developed in Alberta. For the purposes of the 2021 LTO, EVs are modelled as one-way load drivers over the assessed period. The AESO will monitor these advancements in Alberta and adjust EV modelling accordingly.

EV charging can take many load profiles, depending on the type of vehicles (car vs truck) and intended use. As such, the 2021 LTO assumes separate winter and summer weather load profiles that vary between weekdays and weekends. This differentiation represents increased power demand for heating and decreased efficiency of engines and batteries from colder temperatures during the winter months compared to summer conditions, and also reflects unique driving ranges and needs depending on the day of the week. The charging profiles are in line with an engineering study of electric vehicle performance in cold winter-peaking jurisdictions like Alberta.²² The EV methodology represents a non-time-of-use pricing. All vehicles are assumed to follow the same charging profile, and these profiles are maintained constant over the forecast period in the 2021 LTO.

FIGURE 7: Electric Vehicle Charging Profiles



3.3.6 Energy Storage Forecasting Methodology

At present, energy storage makes up a very modest portion of the electricity supply and demand in Alberta. The 2021 LTO forecasts increasing amounts of energy storage, based on extrapolated trends. The AESO expects that as battery storage technologies advance, costs will decline and additional projects will be added to the market in order to supply unique opportunities, such as ancillary services. The energy storage volumes in the 2021 LTO are added exogenously to the forecast model.

²² For more details, see ICF, Electric Vehicle Investigation Submitted to Yukon Energy Corporation, (February 2016); https://yukonenergy.ca/media/site_documents/Yukon_EV_Investigation_Report.pdf

4.0 2021 LTO Results

4.1 REFERENCE CASE

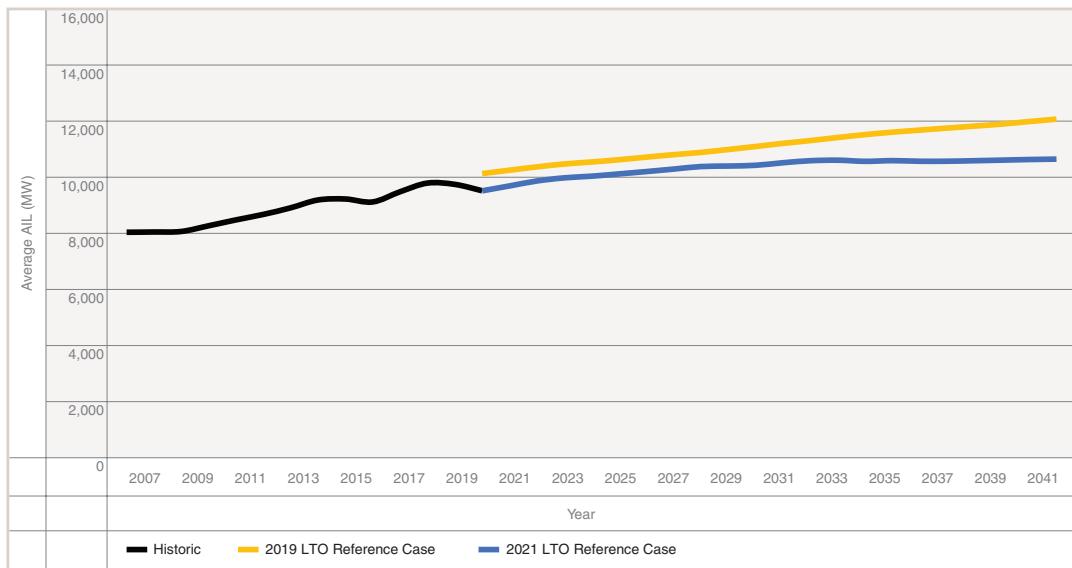
The Reference Case represents the long-term impact of the most recent economic outlook for the province, the current policy and regulatory landscape, and the most up-to-date information on capital costs and trends of prevailing technologies in Alberta. The Reference Case anchors the AESO's current view on the future of the energy market in Alberta and therefore is considered as the main corporate forecast.

4.1.1 Load Forecast

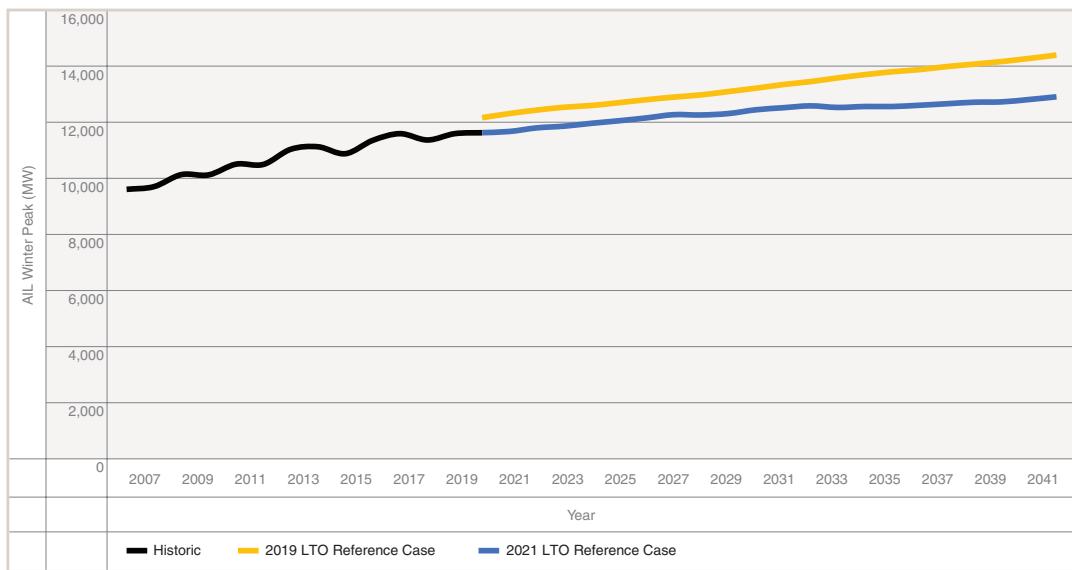
The Reference Case load forecast indicates that the AIL growth has entered a relatively slow and steady growth phase due to a number of factors. The Alberta economy is expected to maintain a slightly downward trend for electricity intensity, as established sectors of the economy (e.g., bitumen production, manufacturing) improve their energy efficiency and new incoming industries are less energy intensive. The impact of restrictions due to the COVID-19 pandemic's public health measures is forecast to restrain AIL growth in the near term as the province turns the corner on the pandemic. Lastly, and more relevant to the medium-and long-term prospects, load growth is projected to follow a slower-paced upward trend due to small-scale expansion at oil sands sites, slower GDP growth, as well as increased penetration of DER.

The 2021 LTO Reference Case forecast is lower than Reference Case results in past LTO reports due to the pandemic, lower economic and oil sands production outlooks. The compound annual growth rate (CARG) for the period of 2021 to 2041 is 0.5 per cent as compared to the 0.8 per cent in the 2019 LTO for the same period.²³

²³ The 2019 LTO can be found here: <https://www.aeso.ca/assets/Uploads/AESO-2019-LTO-updated-10-17-19.pdf>

FIGURE 8: Average AIL Forecast

Alberta is expected to remain a winter-peaking jurisdiction over the forecast period. Annual peak load growth is projected to be 0.5 per cent from 2021 to 2041, aided in part by incremental load from EV charging.

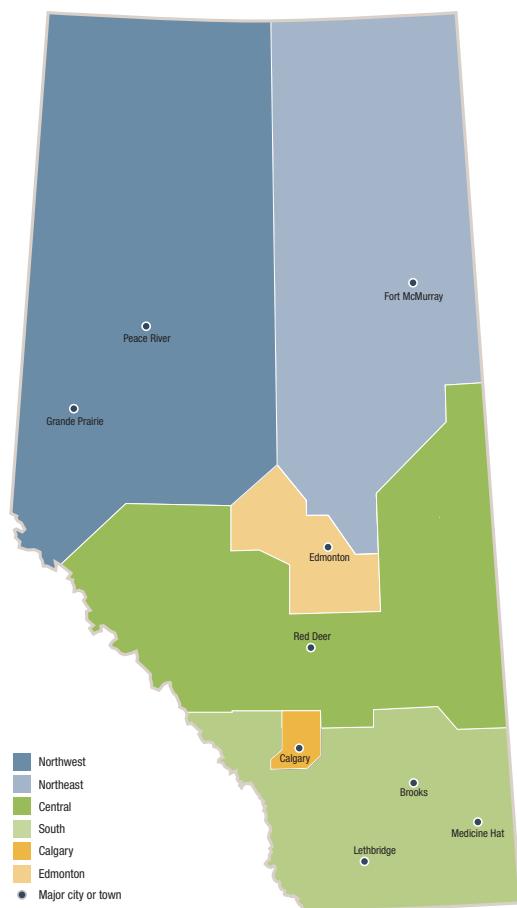
FIGURE 9: AIL Peak Forecast²⁴

²⁴ The 2021 LTO relies on different time intervals to display average and peak forecast data. Average energy is typically displayed in calendar years, starting in January and ending in December of year Y. Peak load is based on the AESO's definition of seasonal years, whereby Summer covers May thru October of year Y and Winter includes November of year Y thru April of year Y + 1. For example, 2020 winter peak is the highest load consumed from November 1, 2020 to April 30, 2021.

4.1.2 Regional Load Forecast

The 2021 LTO is an input to transmission planning studies and examines the features of each specific AESO Planning Region as well as key drivers affecting electricity consumption and generation within those regions.²⁵ Assessing load drivers by region assists the AESO in understanding the local and geographic-specific impacts associated with forecast load.

FIGURE 10: AESO Planning Regions



The Northwest Planning Region represents approximately 11 per cent of the total AIL. Most of the electricity consumption in the northwest region comes from industrial activities such as pulp and paper mills, conventional oil and gas processing and condensates production. It is a winter-peaking region and the winter peak load has grown 0.6 per cent over the past 10 years. The average load in the region dropped in 2020 due to a reduction in economic activities stemming from the COVID-19 pandemic and low oil prices. The 2021 LTO forecasts moderate load growth in the Northwest Planning Region, slightly offset by increased penetration of distribution-connected gas-fired generation.

The Northeast Planning Region represents about 30 per cent of the total AIL. The economy in this region is heavily driven by the oil sands industry. As such, load growth mostly comes from the electricity consumption at oil sands facilities. The load growth in the region has been the strongest among all regions due to the rapid escalation of oil sands development over the past two decades. The 2021 LTO projects load growth to remain strong in the near term due to the ramp up of existing oil sands and other industrial projects that cut back production

during the pandemic and recent low oil price environment. In the medium and long term, however, load growth is expected to taper off given that subsequent construction and expansion projects will be smaller in scale.

The Edmonton Planning Region includes the City of Edmonton, St. Albert, Sherwood Park, Spruce Grove, Leduc and the Wabamun Lake area. This region currently represents about 16 per cent of Alberta's load and consists of residential, commercial and industrial loads such as oil refining, manufacturing and pipelines. Although annual load growth was strong in the 2010s, it began to flatten from 2017 onwards due to adverse economic conditions in the Edmonton metropolitan region. The 2021 LTO forecast for the Edmonton Planning Region continues to be relatively flat due to the combination of timid growth in load drivers specific to the Edmonton metropolitan region, an increase in rooftop solar adoption and gains in energy efficiency.

²⁵ The AESO developed planning regions to evaluate the needs of the bulk system to move power between the regions. The planning regions are further divided into smaller planning areas to facilitate detailed engineering evaluations of the transmission system in specific areas of each region. The regional and area designations are based on the unique load and generation characteristics of the various parts of the province. For a full list of the planning areas and corresponding regions, see <https://www.aeso.ca/assets/Uploads/Planning-Regions.pdf>

The Central Planning Region spans the province east-west between the borders of British Columbia and Saskatchewan, and north-south between Cold Lake and Didsbury. Its major population centres are the cities of Red Deer, Hinton and Lloydminster. The Central Region contains notable amounts of manufacturing and farming, and there is significant oil sands development in the Cold Lake area. The Central Planning Region also features a considerable number of pipelines, and commercial and industrial loads that depend on the growth of the oil and gas sector. It currently represents 18 per cent of Alberta's AIL load. Over the past 10 years, the regional winter peak has grown by an average annual rate of 0.9 per cent. Over the forecast horizon, this region is expected to have moderate adoption of rooftop solar generation (in the main population centres) and distribution-connected gas-fired generation (in the highly industrial areas) which will have a combined effect of slightly offsetting load growth. The 2021 LTO forecasts that the winter peak load continues to grow due of increasing oil sands production as well as pipeline and other industrial activities.

The Calgary Planning Region includes the City of Calgary, Airdrie and surrounding vicinities. The region is characterized primarily by urban load, including significant residential and commercial demand, as well as some industrial load. This region currently represents about 12 per cent of the total AIL and has potential to peak in either winter or summer months depending on the prevailing temperatures. Over the past 10 years, summer peak average annual load growth has been 0.9 per cent while winter peak has declined by 0.2 per cent. The economic conditions of the Calgary metropolitan area were deteriorating before the pandemic and an economic recovery is expected to occur over multiple years. A slow-growth economic outlook, coupled with increased penetration of rooftop solar adoption and energy efficiency gains, translates into a flat growth profile for the Calgary Planning Region over the forecast horizon.

The South Planning Region stretches from Canmore and Kananaskis in the west to Empress in the east and Brooks, the cities of Lethbridge and Medicine Hat in the southern part of the province. The economic diversity of this region is reflected in its energy consumption from multiple industrial and commercial load types including pipelines, natural gas processing, manufacturing, farming and agriculture, meat and agri-food processing, and tourism and hospitality. This region currently represents about 11 per cent of the total AIL and generally peaks in the summer season due to air conditioning and agricultural demands throughout the region. The summer peak load has grown by an average of 0.5 per cent over the past 10 years. Though the area experienced a load drop in 2020, the 2021 LTO projects load recovery in 2021-2022 and moderate load growth thereafter, offset in part by increased penetration of rooftop solar generation and, to a lower extent, distribution-connected wind farms.

The difference between the sum of regional load and AIL reflects transmission losses. Transmission losses represent about 2.8 per cent of system load (see Section 5.1.2 System Load below for more details), and the 2021 LTO maintains this general trend over the forecast period.

4.1.3 Generation Outlook

The 2021 LTO includes a diverse set of generation additions in the forecast. Many projects are supported by power market economics, taking into account electricity-related revenues and costs, while others are driven by several other revenue streams. Cogeneration additions are based on economics of oil and gas projects, integrating electricity as one revenue stream within the broader project. Renewables projects benefit from revenues associated with the environmental attributes created alongside their generation. In the 2021 LTO, cogeneration and most renewables projects are added exogenously, based on multiple market factors, whereas combined-cycle natural gas, simple-cycle natural gas, and some renewables projects are added based on electricity market fundamentals.

The 2021 LTO Reference Case is predicated on the current TIER carbon regulation in Alberta. As such, the carbon price assumption escalates to \$40-per-tonne in 2021, per Ministerial Order 36/2020, and increases to \$50-per-tonne in 2022 to align with the federal Greenhouse Gas Pollution Pricing Act, Schedule 4, and announcements by the Government of Alberta.

TABLE 4: Estimated Carbon Price Impact by Generator Type

Generator Type	Estimated Heat Rate, GJ/MWh	Estimated Carbon Intensity, t/MWh	Regulated “High-Performance Benchmark”, t/MWh	Carbon Price (2022), \$/t	Generator Cost of Carbon, \$/MWh
Sub-Critical Coal	12.5	1.00	0.37	\$50	\$31.50
Coal-to-Gas Boiler Conversion	12.5	0.70	0.37	\$50	\$16.56
Simple-Cycle Gas	9.68	0.54	0.37	\$50	\$8.65
Combined-Cycle Gas	7.0	0.39	0.37	\$50	\$1.14
Renewable Generation (EPCs) ²⁶	N/A	0.00	0.37	\$50	-\$18.50
Renewable Generation (Offsets)	N/A	0.00	0.53	\$50	-\$26.50

Fossil fuel generators using coal as a fuel source will continue to experience the largest cost pressure under \$50-per-tonne; combined-cycle natural gas generators will experience a modest increase in carbon costs.

Renewables generators will benefit from the diversified revenue available from the sale of renewable attributes that are additional to their energy income. The value of renewable attributes can be monetized in a variety of ways:

- Bilateral sales to voluntary renewable electricity buyers
- Sale or compliance use of registered carbon offsets
- Sale or compliance use of emission performance credits (EPCs)

²⁶ Emission Performance Credits or EPCs can be created by renewable facilities under section 20 of the TIER Regulation, and these credits can be used as a carbon compliance mechanism.

In the near term, registered offsets are expected to be a more valuable mechanism to monetize than EPCs, but that relationship is susceptible to change. The value of renewable attributes from certain renewables generation forms can currently be converted to offsets using the electricity grid displacement factor (EGDF) of 0.53 tonnes per MWh. When the EGDF is multiplied by the carbon price, the dollar per MWh value of renewable attributes monetized as offsets can be derived. The EGDF is the approximate carbon intensity of the electrical grid, based on a lagging build margin and operating margin calculation, with a 50 per cent weighting on each component. As such, it will likely decline as emissions-intensive technologies operate less frequently and cleaner technologies are constructed and operated more frequently. At some point in the future, the EGDF is likely to drop below 0.37 tonnes per MWh, when it will be profit maximizing for new renewable generators to “opt-in” to the TIER regulation and create EPCs instead of offsets.

As an alternative to either compliance mechanism, renewable generators can also sell their attributes (or bundled attributes plus energy) to third parties interested in elective renewable energy purchases. The 2021 LTO generation forecast evaluates renewable attributes based on the value of offsets, with the expectation that EGDF will decline to 0.37 tonnes per MWh within the forecast period.

In many recent cases, corporations have engaged in renewable PPAs with renewable developers. PPA contracts can help corporations achieve their environmental, social, and governance (ESG) objectives, while enabling the development of renewables projects with a low risk revenue stream. The 2021 LTO Reference Case recognizes the growing trend of corporate PPAs, with 1,280 MW of corporate PPAs forecast by 2041. Corporations and voluntary renewables attribute buyers in Canada have limited options for renewable PPAs situated outside of the Alberta market. Although many of the renewable projects built to support corporate PPAs are situated in Alberta, some customers may be situated outside of the province.

Relative generator costs are a major determinant of incremental generation fleet additions. The 2021 LTO Reference Case makes the following assumptions regarding new generator costs (values in 2021 dollars).²⁷

TABLE 5: Generation Capital and Operating Cost Assumptions

Generator Type	Unit Size, MW	Capital Cost, \$/kW	Fixed Operating Maintenance Costs, \$/kW-yr	Unit Heat-Rate, GJ/MWh	Variable Operating Maintenance Costs, \$/MWh
Combined-Cycle Natural Gas	479	1,667	49.71	7.03	2.49
Simple-Cycle Natural Gas (Aero-derivative)	46.5	1,159	52.83	9.68	4.24
Wind Generator, 2021-2025	50	1,586	36.40	N/A	-
Wind Generator, 2026+	50	1,105	32.50	N/A	-
Solar Generator, 2021-2025	50	1,643	33.70	N/A	-
Solar Generator, 2026+	50	1,388	31.88	N/A	-

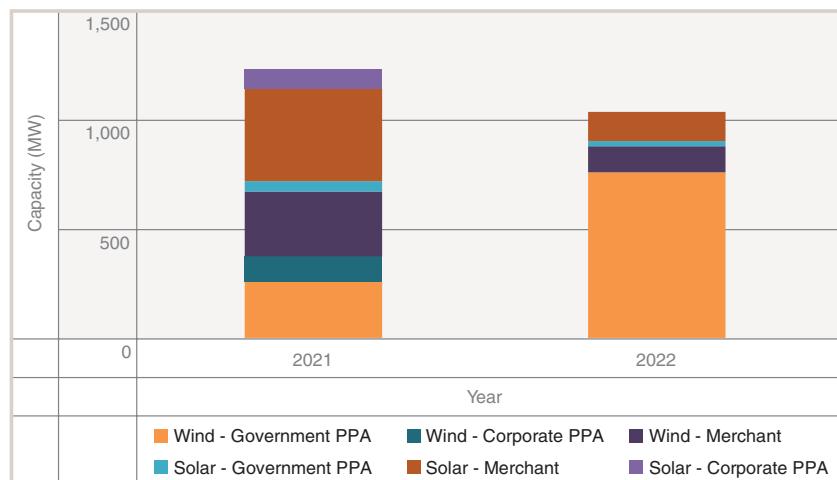
²⁷ Renewable cost estimates were derived from: <https://www.aeso.ca/assets/Uploads/AWS-TruePower-AESO-Wind-and-Solar-Assessment.pdf>. Fossil-fuel generator costs were based on recently built and planned projects.

The Reference Case forecasts the development of 12,193 MW of new or substantially modified generation in Alberta over the next 20 years. The new generation development can be split into two groups: specific projects that have reached the AESO project inclusion criteria, and generic builds that are forecast using the economics of those technologies and policy drivers.

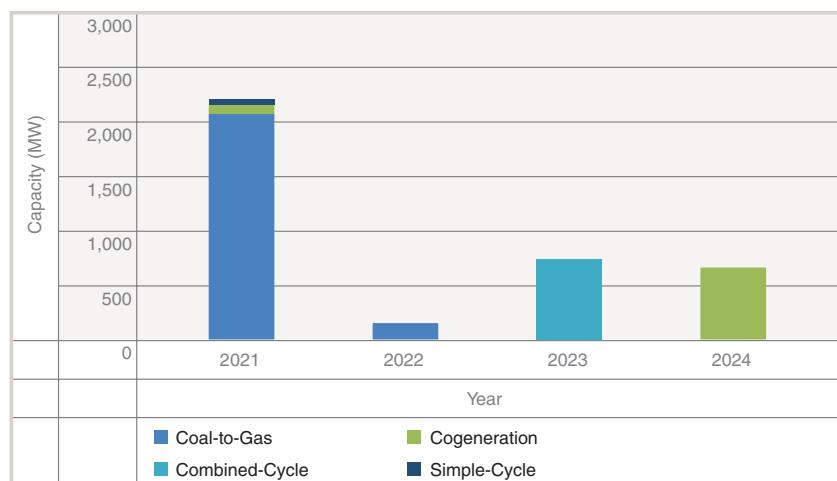
Near-term projects that meet the project inclusion criteria include solar, wind, simple-cycle, combined-cycle and cogeneration that are forecast to come into service between 2021 and 2024. Major near-term natural gas-fired projects include Suncor coke boiler replacement cogeneration project, the Fengate cogeneration project, the Cascade combined-cycle project, and the City of Medicine Hat Unit 17 simple-cycle project. A significant number of renewables projects are also included in 2021 and 2022, including 718 MW of solar projects and 1,547 MW of wind projects. Many of the renewable projects were contracted under the REP or other government contracts (such as Alberta Infrastructure), while others represent corporate PPAs or merchant-renewables projects.

FIGURE 11: Near-Term Capacity Additions

Near-Term Renewable Capacity Additions



Fossil Fuel Capacity Additions 2021 to 2024



In addition to the specific thermal projects that have achieved the AESO connection process project certainty criteria, most of the historical coal fleet is expected to convert the coal boilers to natural gas operation. Table 6 outlines the expected coal-to-gas conversion dates for these units in the Reference Case. The conversion of over 3,000 MW of coal-fired generation to natural gas fired capacity represents a substantial shift in the Alberta generation fleet, and a meaningful move towards a cleaner electricity generation landscape.

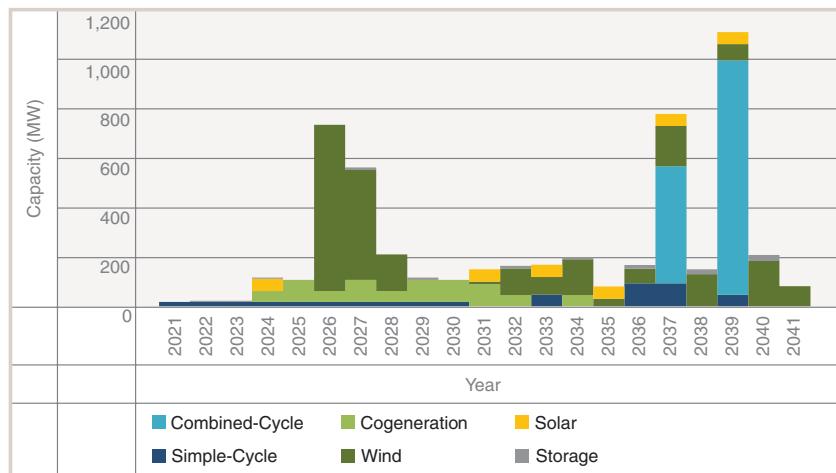
TABLE 6: Reference Case Coal-to-gas Conversion Dates and Capacity

Unit Name	Capacity (MW)	Conversion Year	Retirement Year
Battle River 4	155	Partial conversion to gas, no full conversion assumed	2025
Battle River 5	385	2020	2032
Genesee 1	400	2021	2036
Genesee 2	400	2021	2036
Genesee 3	466	2021	2037
Keephills 1	395 MW in 2021 and 70 MW in 2022 and onwards	No full conversion, only partial conversion assumed	2029
Keephills 2	395	2021	2034
Keephills 3	463	2021	2037
Sundance 4	406 MW in 2021 and 113 MW in 2022 onwards	No full conversion, only partial conversion assumed	2027
Sundance 5	406	2022	2033
Sundance 6	401	2020	2033
Sheerness 1	400	2021	2035
Sheerness 2	400	2020	2035

The 2021 LTO Reference Case includes 1,280 MW of renewables projects that are expected to be developed by 2041 to supply renewable corporate PPAs. This includes 1,030 MW of wind and 250 MW of solar generation capacity. Economic merchant wind additions are expected to supply 550 MW of additional renewable capacity, while merchant solar additions are expected to supply 50 MW of additional capacity. When added to the near-term projects, 3,127 MW of wind capacity and 1,018 MW of solar capacity is forecast to be added to the Alberta market by 2041.

Longer term cogeneration additions include 675 MW of cogeneration projects, expected to compliment greenfield oil sands projects. Simple-cycle natural gas generation is expected to add 446 MW of capacity, while combined-cycle natural gas generation is expected to add 1,437 MW of capacity.

The Reference Case also includes 115 MW of new battery storage projects and 35 MW of hybrid projects combining battery storage with an additional source of supply. Batteries are expected to provide unique energy services, such as ancillary services, in the Reference case and are forecast to total 150 MW of capacity by 2041.

FIGURE 12: Reference Case: Alberta Generic Generation Additions

The generic additions in Figure 12: Reference Case Alberta Generic Generation Additions exclude known near-term projects that have met the project inclusion criteria. These projects have been included in Figure 13, Forecast and existing generation capacity (Reference Case), below.

A large portion of forecast load growth in the Reference Case is related to oil sands and this growth is expected to include 675 MW of greenfield oil sands-based cogeneration development over the forecast horizon. The forecast retirement of existing coal and coal-to-gas converted units provides opportunities for new combined-cycle and simple-cycle in the 2030s. There are also opportunities for renewable generation to enter the market and compete with existing assets with development expected throughout the forecast horizon.

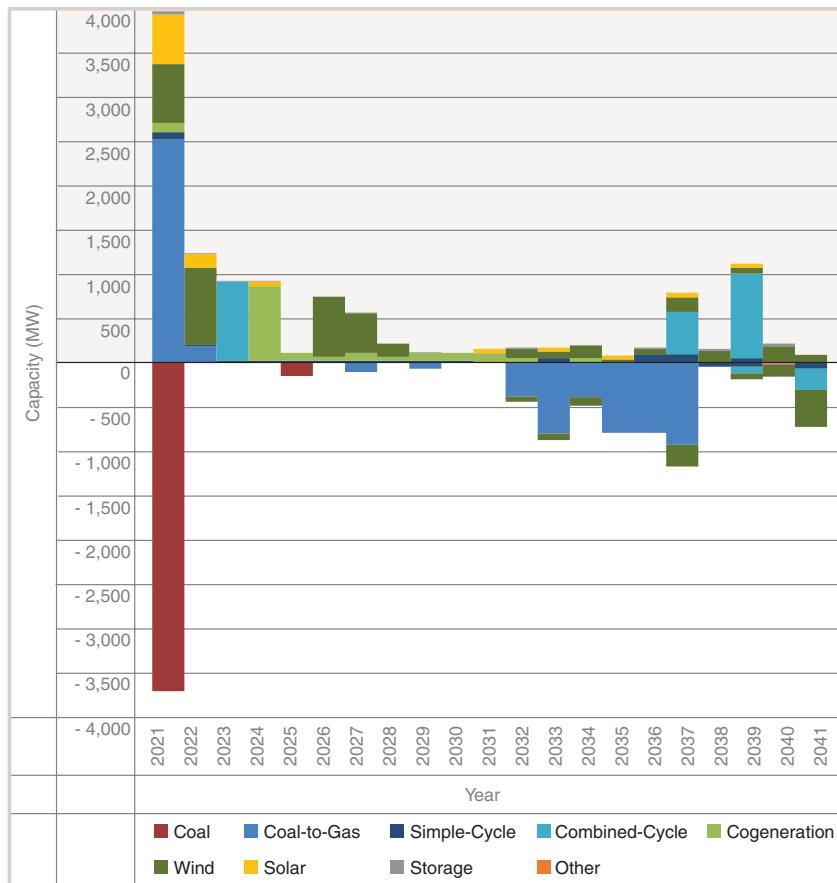
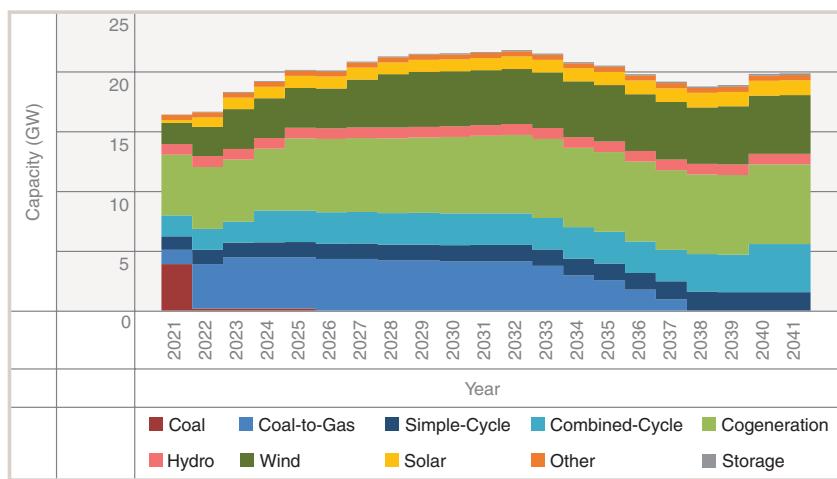
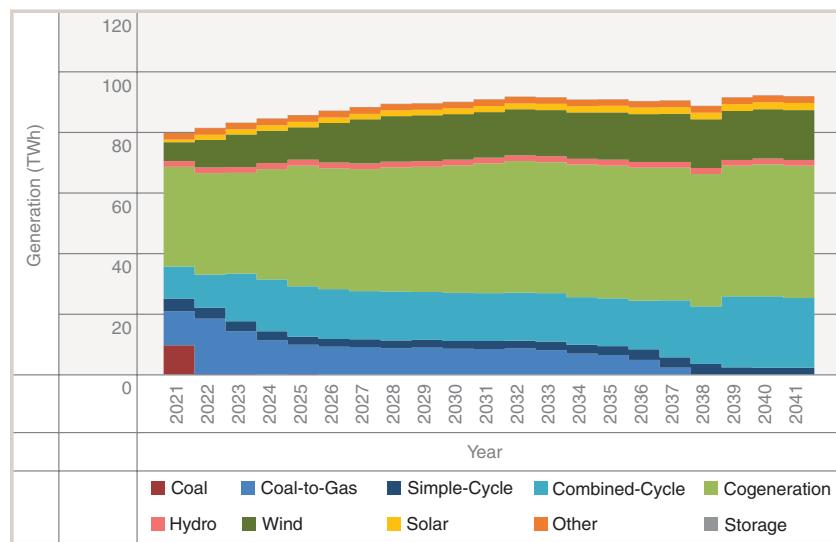
FIGURE 13: Reference Case: New and Retired Capacity by Fuel Type**FIGURE 14: Reference Case: Capacity by Fuel Type**

FIGURE 15: Reference Case: Alberta Generation

The Reference Case depicts a changing generation landscape, with reduced reliance on coal generation and increased reliance on natural gas generation. Throughout the forecast term, natural gas fired technologies are expected to generate between 75 per cent and 82 per cent of annual electricity in the province. Renewable generation exhibits strong growth throughout the forecast term. Increasing amounts of variable generation may pose challenges to reliable system operations if these changes are not managed prudently. The AESO will continue to monitor system stability and operational capability through flexibility assessments.²⁸

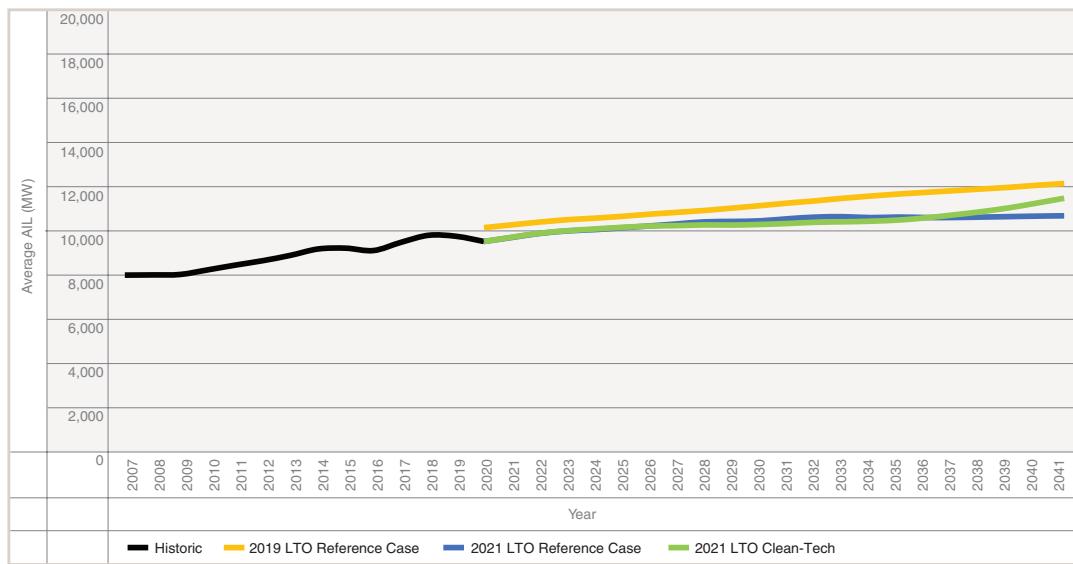
4.2 CLEAN-TECH SCENARIO

The Clean-Tech scenario represents a major transformation of the Alberta electricity sector based on two key drivers. First, global trends towards decarbonization translate into stalled growth in the domestic energy sectors, thus lowering the projected economic and oil sands outlook used in the Reference Case. The second trend is driven by federal carbon policies that make renewable generation investments in Alberta more attractive. The Clean-Tech scenario also assumes 20 per cent capital cost reductions for wind and solar generation, compared to the Reference Case. Lastly, consumer behavior is assumed to change to favour higher energy efficiency products, increased adoption of DER and greater transport electrification.

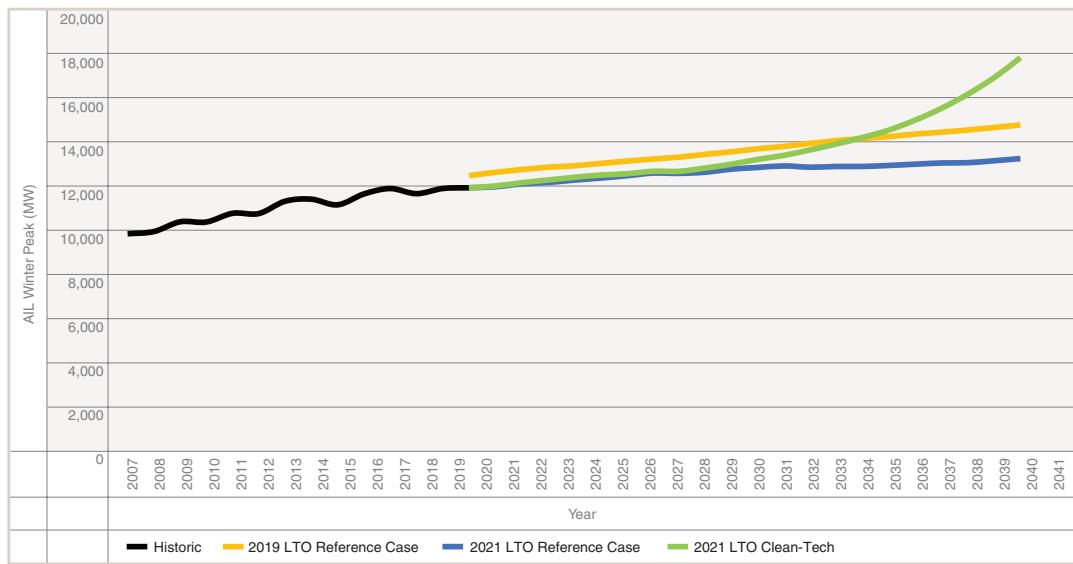
4.2.1 Load Forecast

The Clean-Tech load forecast represents a boundary condition that tests a major departure of the traditional load drivers and profiles experienced in Alberta to date. Lower oil sands production and economic growth reduces the pace and magnitude of AIL growth over the entire forecast period. Greatly offsetting remaining AIL growth is the rapid pace of DER adoption – particularly the expected increase of rooftop solar to over 2,000 MW by 2041. This combined effect of lower general growth and the addition of DER generation results in slower AIL growth until the mid-2030s, when compared to the Reference Case. In the latter half of the 2030s, the cumulative impact of EV charging – assumed to reach one-third of the entire vehicle stock in Alberta – pushes AIL growth well above the Reference Case by 2041.

²⁸ An example of the most recent system flexibility assessment can be found here: <https://www.aeso.ca/assets/Uploads/AESO-2020-System-Flexibility-Assessment-FINAL-jul-17.pdf>

FIGURE 16: Clean-Tech Average AIL Forecast

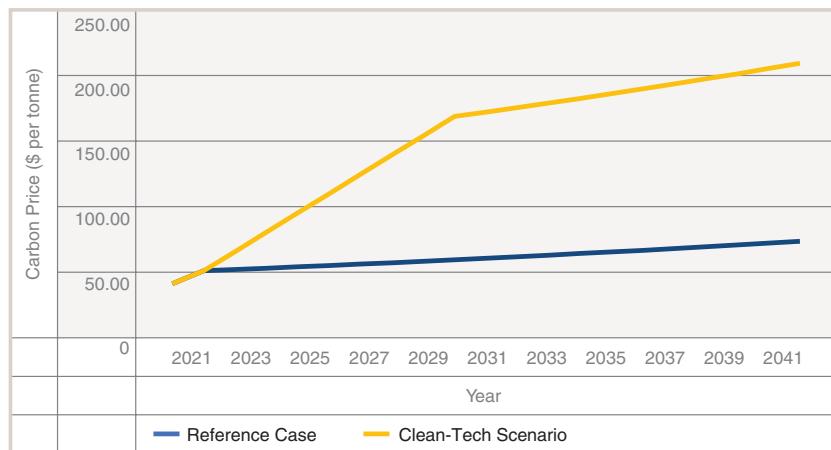
The impact of electric vehicle load is particularly acute during winter peaking conditions. The assumed charging profile is concentrated around the evening hours, which also coincide with the maximum general energy consumption patterns of Albertans. Under the Clean-Tech scenario, peak load begins to significantly diverge from the Reference Case around 2030 and reaches more than 17,000 MW by winter 2041, equivalent to 34 per cent higher than the Reference Case.

FIGURE 17: Clean-Tech Peak AIL Forecast

4.2.2 Generation Outlook

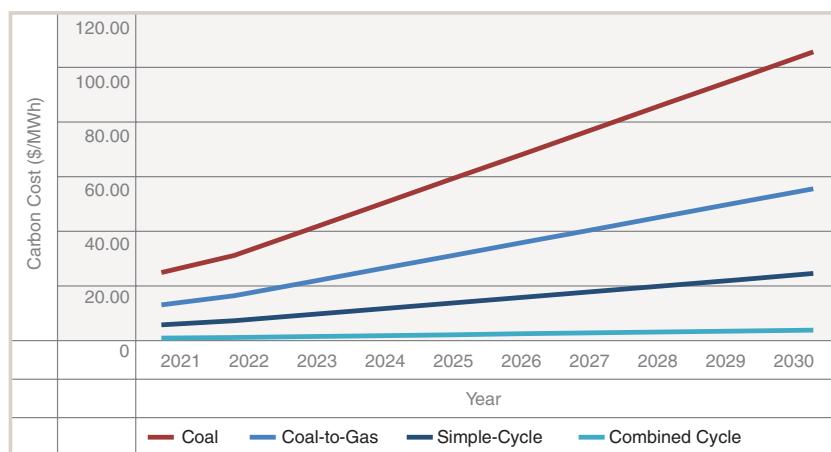
The Clean-Tech scenario is based on the federal \$170-per-tonne 2030 carbon price, as announced in December 2020. For the purposes of the Clean-Tech Scenario, the TIER Regulation is expected to maintain equivalency to federal carbon regulations and remain applied in the Province of Alberta.

FIGURE 18: Carbon Price Assumptions



Fossil fuel generators using coal and simple-cycle will experience the largest cost pressure under \$170-per-tonne, while combined-cycle natural gas generators will experience a modest increase in carbon costs. The Clean-Tech Scenario assumes that Genesee 1, Genesee 2, and Sundance 5 coal units will be repowered as combined-cycle units. Combined-cycle generators will pay the lowest carbon costs, which are magnified in this scenario. As a result, the incremental investment required to repower the former coal units as combined-cycle facilities is a more compelling investment than portrayed in the Reference Case. Due to increased carbon prices and the resulting impact on inefficient fossil fuel generators, this scenario anticipates that most of the coal-to-gas units will retire earlier than the Reference Case. Conversely, cogeneration is expected to increase by 135 MW by 2041 in the Clean-Tech scenario when compared to the Reference Case. Efficient cogeneration projects are expected to generate EPCs that are more valuable in this scenario, due to the increased carbon price. Simple-cycle generation is expected to increase by 515 MW by 2041 compared to the Reference Case, while combined-cycle generation is expected to increase by 737 MW by the end of the forecast.

FIGURE 19: Carbon Cost of Fossil Fuel Generators in Alberta Under TIER with \$170-per-tonne Carbon Price



In the Clean-Tech scenario, wind and solar capital costs are expected to decline by 20 per cent, driven by technological advancements. This will result in increased competitiveness for renewable technologies, including additional corporate PPA development opportunities. The value of renewable attributes is forecast to increase as a result of the increasing carbon price, further enhancing the value of clean generation sources. Many renewables projects will be used to produce offsets or emissions performance credits and these projects will be economic based on the value derived from these renewable attributes. The value of renewable attributes is expected to substantially compensate the investment costs of renewable generation facilities. Additional revenue can be achieved from the sale of electricity to the power pool, resulting in diverse and robust revenue streams for low-cost renewable generation.

Renewables cost declines are also expected to impact solar roof-top installations at residential, commercial and industrial sites in Alberta. The Clean-Tech scenario forecasts over 2,000 MW of roof-top solar photovoltaic installation by 2040.

In this scenario, the development of diverse technologies such as geothermal (100 MW) and pumped hydro storage (75 MW) are also forecast.

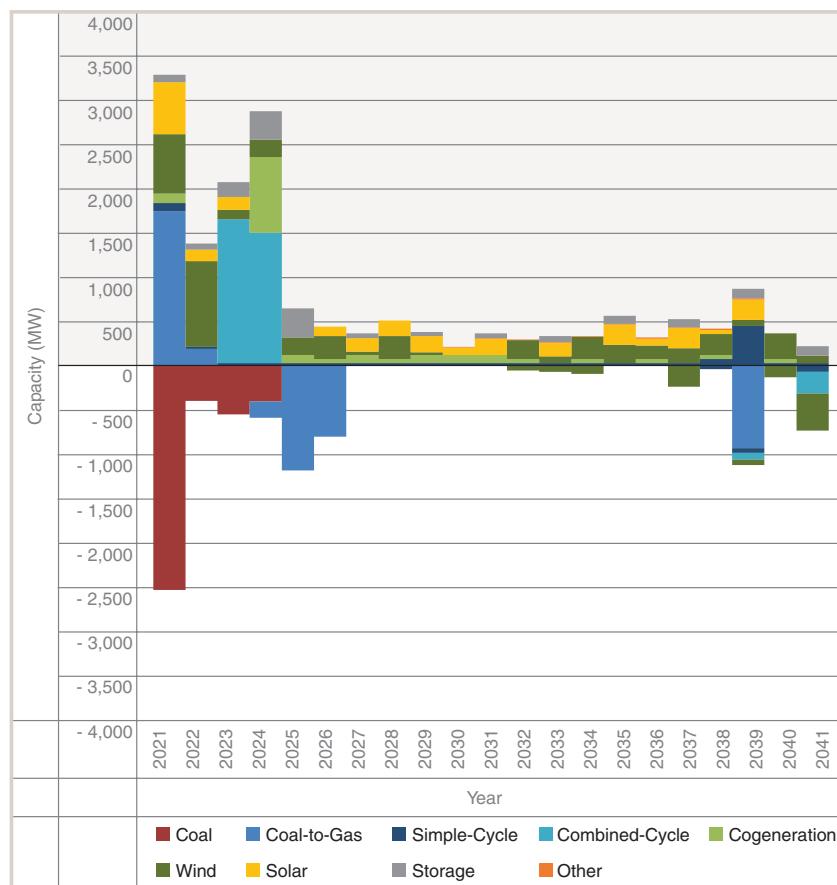
The Clean-Tech scenario also assumes significant cost reductions in energy storage, leading to increased opportunities for the technology and its applications in the Alberta power market.

The Clean-Tech scenario results compared to the Reference Case include higher renewable generation by the end of the forecast period. The percentage of generation from renewable sources is increased to 25 per cent by 2031 and 30 per cent by 2041. The Clean-Tech scenario also results in additional combined-cycle, simple-cycle and cogeneration compared to the Reference Case, therefore supporting intermittent resources and increasing electric vehicle load towards the end of the forecast period.

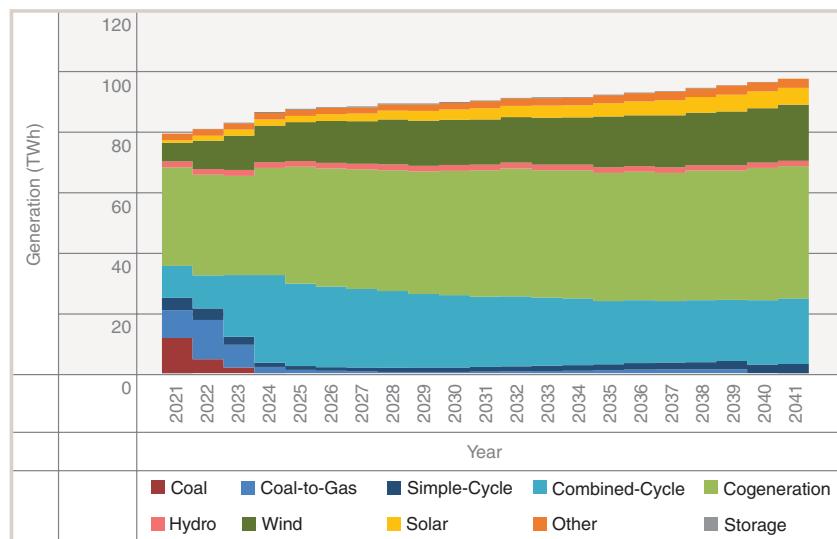
The improved economics of renewables leads to a significant increase in solar capacity of 1,680 MW by 2041 relative to the reference case. Wind additions also increase by 540 MW compared to the Reference Case. Storage additions increased by 1,370 MW compared to the Reference Case.

The Clean-Tech scenario has significant energy storage capacity consisting of 1,520 MW of total capacity by 2041. This consists of 1,250 MW of battery storage, 75 MW pumped hydro storage and 195 MW of hybrid units. In the Clean-Tech scenario, storage is expected to exploit energy arbitrage and ancillary service opportunities. As with the other scenarios, storage is added exogenously to the Clean-Tech scenario.

Natural gas additions also increase by 1,387 MW compared to the Reference Case, consisting of 515 MW of incremental simple-cycle, 737 MW of incremental combined-cycle, and 135 MW of incremental cogeneration capacity. Natural gas additions displace retired coal and coal-to-gas capacity, since the relative economics of newer natural gas technologies are much more attractive under the higher carbon prices depicted in this scenario. The increased amount of natural gas-fired generation aids in providing fast-acting supply to counteract the modified daily load patterns caused by increased on-site solar generation and EV charging load.

FIGURE 20: Clean-Tech Scenario: Alberta Generation Additions and Retirements

The Clean-Tech scenario is predicated on a future generation landscape compromising more renewable generation volume than the Reference Case. However, fossil-fuel generation from natural gas-fired generators provides the majority of electricity supply in the forecast.

FIGURE 21: Clean-Tech Scenario: Alberta Generation

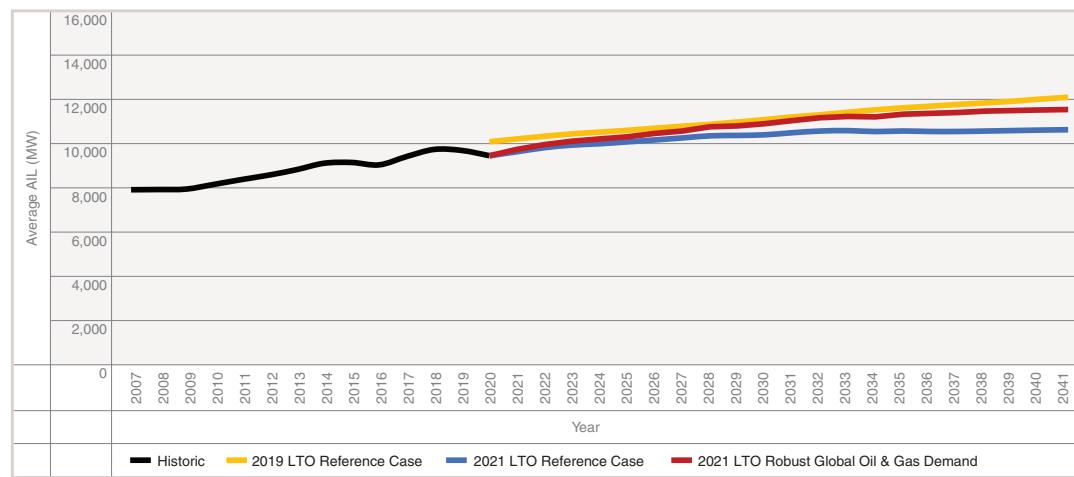
4.3 ROBUST GLOBAL OIL AND GAS DEMAND SCENARIO

The Robust Global Oil and Gas Demand scenario represents a future where global energy needs are growing, and Alberta remains a major contributor to the supply of hydrocarbons. In this scenario, economic growth and population growth both lead to increased demand in the Alberta electricity market. Hydrocarbon prices remain supportive for greenfield investment in the sector, and overall production of raw bitumen is expected to be 25 per cent higher than the Reference Case in the late 2030s. In this scenario, natural gas prices are forecast to be approximately \$1.00-per-gigajoule higher than the Reference Case throughout the forecast period. The forecast is intended to test a return to economic strength in Alberta's resource sector and will assist in planning for a high-case boundary of the electricity sector.

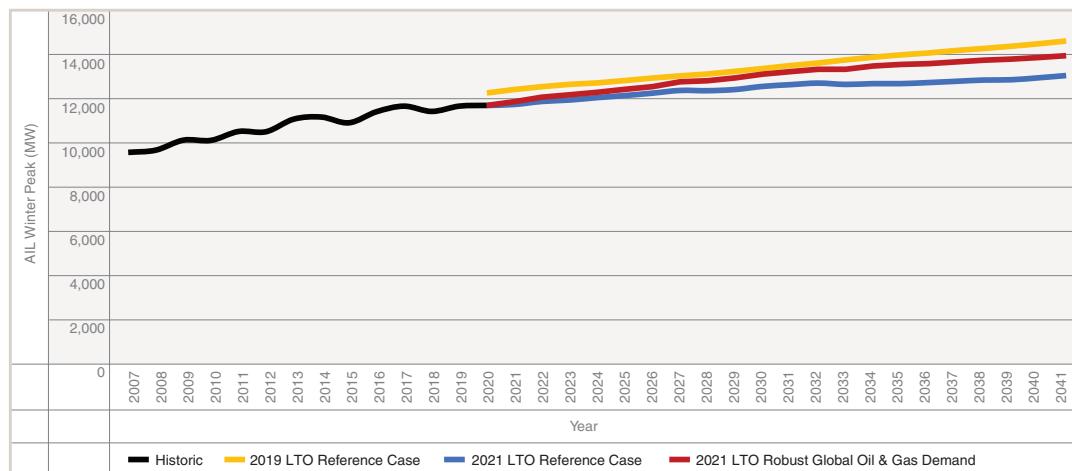
4.3.1 Load Forecast

The Robust Global Oil and Gas Demand scenario is predicated on crude oil prices rebounding and remaining strong in the long term. As a result, oil export capacity increases due to the increased level of pipeline capacity and greater crude-by-rail transportation. It also envisions an expansion of existing Alberta oil sands facilities and the development of new oil sands projects, many of which were previously postponed or deferred, which has a direct positive impact on the load in the northeast and central east part of the province. Condensate demand is also expected to increase because oil sands projects use condensate for transportation of bitumen. The higher demand for condensate and other natural gas liquids results in increased drilling and completion activity in the northwest, increasing load in that part of the province. The increase in oil sands activity leads to higher economic growth in Calgary and Edmonton as well as increased load growth in other regions. The overall impact of these drivers translates into an AIL growth rate of 0.8 per cent per year, reaching levels eight per cent higher than the Reference Case by 2041. Despite being a more aggressive growth scenario, the Robust Global Oil and Gas Demand load forecast is expected to be lower than the 2019 LTO Reference Case.

FIGURE 22: Robust Global Oil and Gas Demand Average AIL Forecast



Peak energy growth follows a similar path under the Robust Global Oil and Gas Demand scenario. Given that most of the assumptions in this scenario impact industrial loads, which tend to have a stable consumption pattern that is not severely altered by weather or time of year, peak load is expected to grow in tandem with overall energy levels at 0.8 per cent per year. The Robust Global Oil and Gas Demand scenario peak load widens over time, up to seven per cent higher than the Reference Case by 2041.

FIGURE 23: Robust Global Oil and Gas Demand Winter Peak AIL Forecast

4.3.2 Generation Outlook

Generation assumptions

Generation development is higher for the Robust Global Oil and Gas Demand scenario compared to the Reference Case. Higher oil sands development drives approximately 1,000 MW additional cogeneration development in the oil sands sector by the end of the forecast term. These cogeneration developments are assumed to be a combination of SAGD (steam-assisted gravity drainage) greenfield oil sands projects and existing sites installing additional cogeneration to replace existing boilers.

The scenario also assumes higher natural gas prices. The scenario uses the Alberta Energy Regulator's (AER) high natural gas price forecast scenario as an input to determine generation development. The higher natural gas price is driven by slower North American tight oil production and higher natural gas demand in the oil sands sector.²⁹

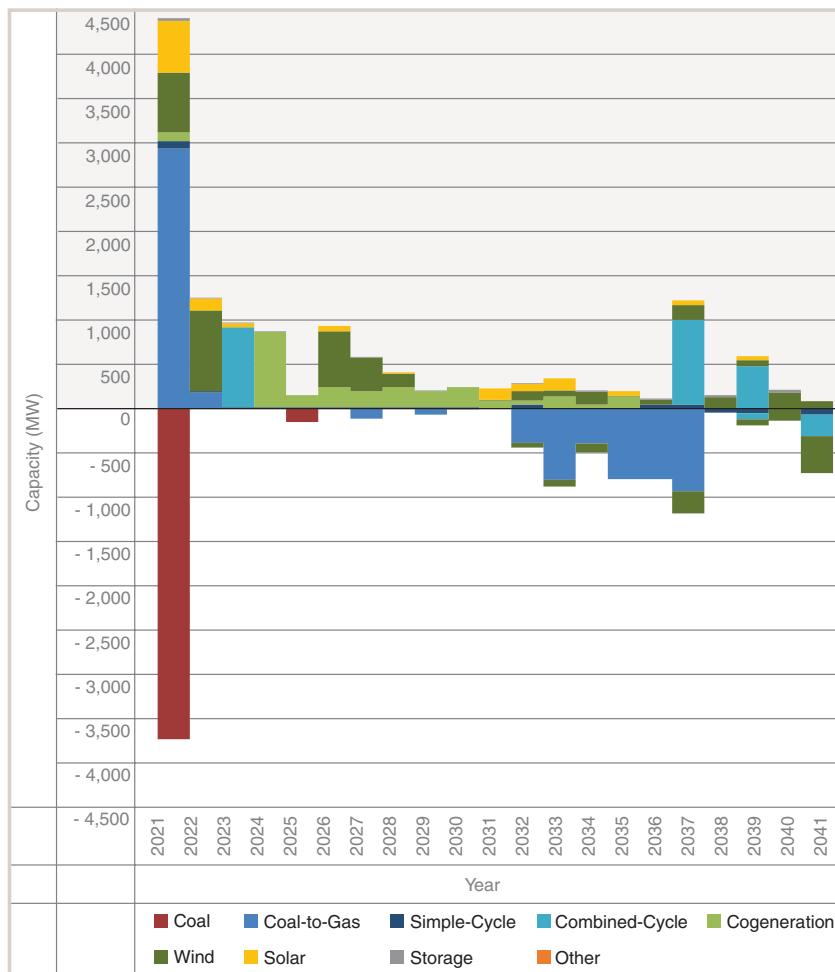
In this scenario, carbon policy, corporate PPA penetration, generation costs, project inclusion, and coal-to-gas conversion/retirement expectations are the same as the Reference Case.

Generation results

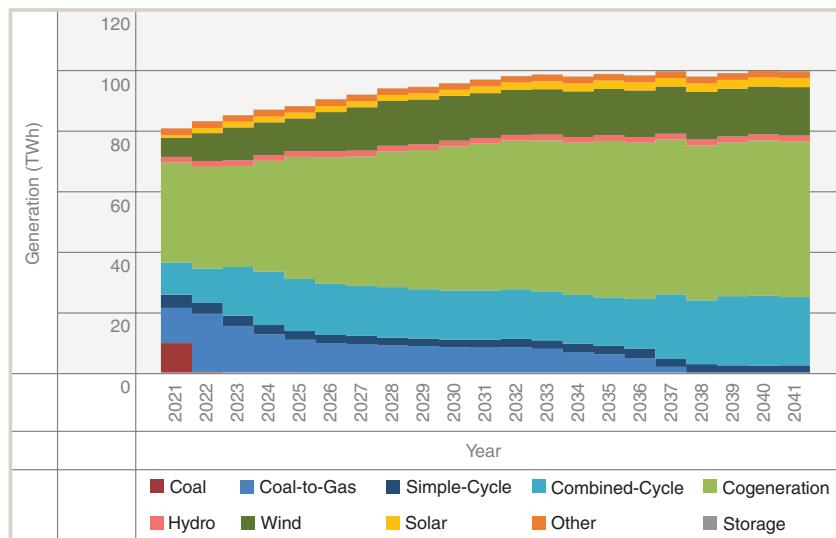
The scenario is dominated by cogeneration development in the oil sands sector. The higher oil sands production forecast includes new oil sands sites that are likely to install cogeneration. Oil sands developers have an incentive to install cogeneration at existing and new sites due to Emission Performance Credits that can be created under the TIER regulation. Cogeneration can also reduce the transmission costs incurred by oil sands companies associated with consuming electricity from the grid.

The combined-cycle development forecast is the same as the Reference Case, coming online once coal-to-gas units have retired in the late 2030s. Solar generation capacity is higher in this scenario compared to the Reference Case, and wind and simple-cycle development are both lower. Solar is well positioned to enter and produce in the summer months when cogeneration electricity output is lower due to the lower oil production at that time of year. Wind and simple-cycle do not see the same opportunities, as they are subordinated by the efficient base-load cogeneration development.

²⁹ See AER ST98 report. <https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98/prices-and-capital-expenditure/natural-gas-prices/aeco-c-price>

FIGURE 24: Robust Global Oil and Gas Demand: Alberta Generation Additions and Retirements

Total generation volumes are the highest in the Robust Global Oil and Gas Demand scenario, in order to meet the highest levels of demand. Renewable generation makes significant contributions to the overall supply mix in this scenario. The remainder of the generation in the province comes from various natural gas-fired sources, with strong growth in cogeneration.

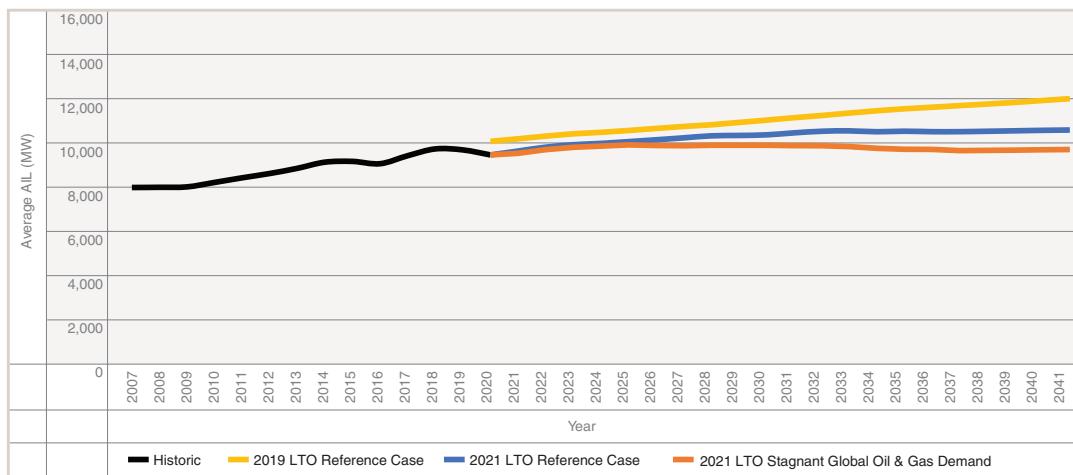
FIGURE 25: Robust Global Oil and Gas Demand Scenario: Alberta Generation

4.4 STAGNANT GLOBAL OIL AND GAS DEMAND SCENARIO

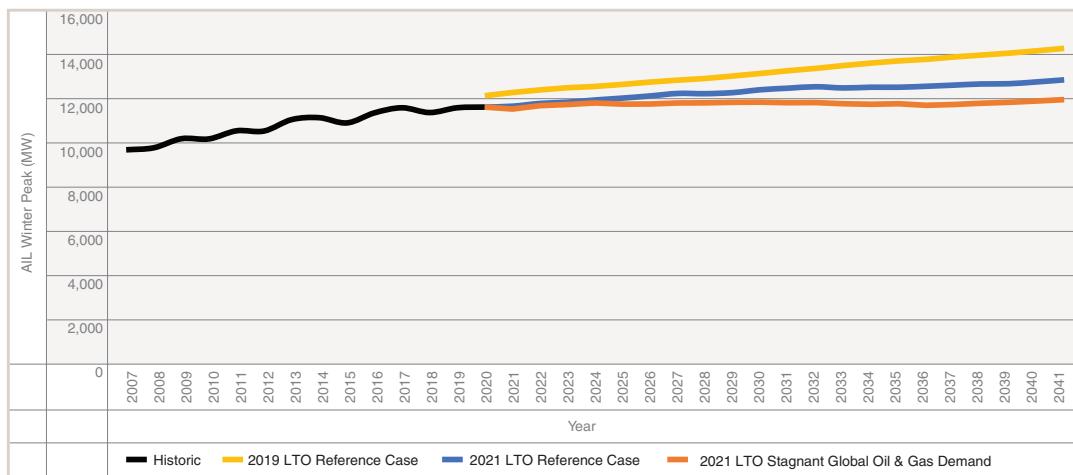
The Stagnant Global Oil and Gas Demand scenario represents a future of decline in global hydrocarbon demand. The impact on key industries in Alberta leads to no growth in hydrocarbon activity. The scenario represents a decline in raw bitumen production of 25 per cent from the Reference Case in the late 2030s, which results in a decline in economic activity and reduced electricity demand. This scenario tests a future where Alberta's electricity sector growth is limited, and energy consumption remains relatively flat. The scenario is intended to assist in planning for a low-case boundary condition where there is limited economic growth and little need for growth-related electricity infrastructure.

4.4.1 Load Forecast

The Stagnant Global Oil and Gas Demand scenario translates into reduced energy consumption levels across multiple sectors in Alberta. The ripple effect of lower oil sands production results lower economic activity and therefore moderate, and in some years, slightly negative load growth across various regions. The slightly negative growth is primarily driven by the moderation in oil sands production and the period in which the economy adjusts to the lower bitumen production levels from 2025 through 2037; after this, population and moderate economic growth combine to keep load growth relatively flat. The role of DER also add to the general moderation in growth of this scenario, as the assumption for DER penetration is similar in pace and magnitude to the Reference Case. Electric vehicle adoption is also assumed the same as in the Reference Case, so the cumulative impact of charging electric vehicles can be seen in the results in the late 2030s. Unlike the rest of the 2021 LTO scenarios, the Stagnant Global Oil and Gas Demand scenario produces an inverse-U shape load forecast, whereby forecast values increase slowly after 2021 but gradually decrease after reaching a peak in the mid-2020s. The compound average growth rate is 0.1 per cent per year from 2021 to 2041.

FIGURE 26: Stagnant Global Oil and Gas Demand Average AIL Forecast

Peak load growth in the Stagnant Global Oil and Gas Demand is slightly higher than average energy growth, thanks largely to electric vehicle charging. Peak load growth is expected to hover around 0.2 per cent per year from 2021 to 2041. Still, the Stagnant Global Oil and Gas Demand peak load trends below the other scenarios and diverges widely over time to seven per cent below the Reference Case by 2041.

FIGURE 27: Stagnant Global Oil and Gas Demand Winter Peak AIL Forecast

4.4.2 Generation Outlook

Generation assumptions

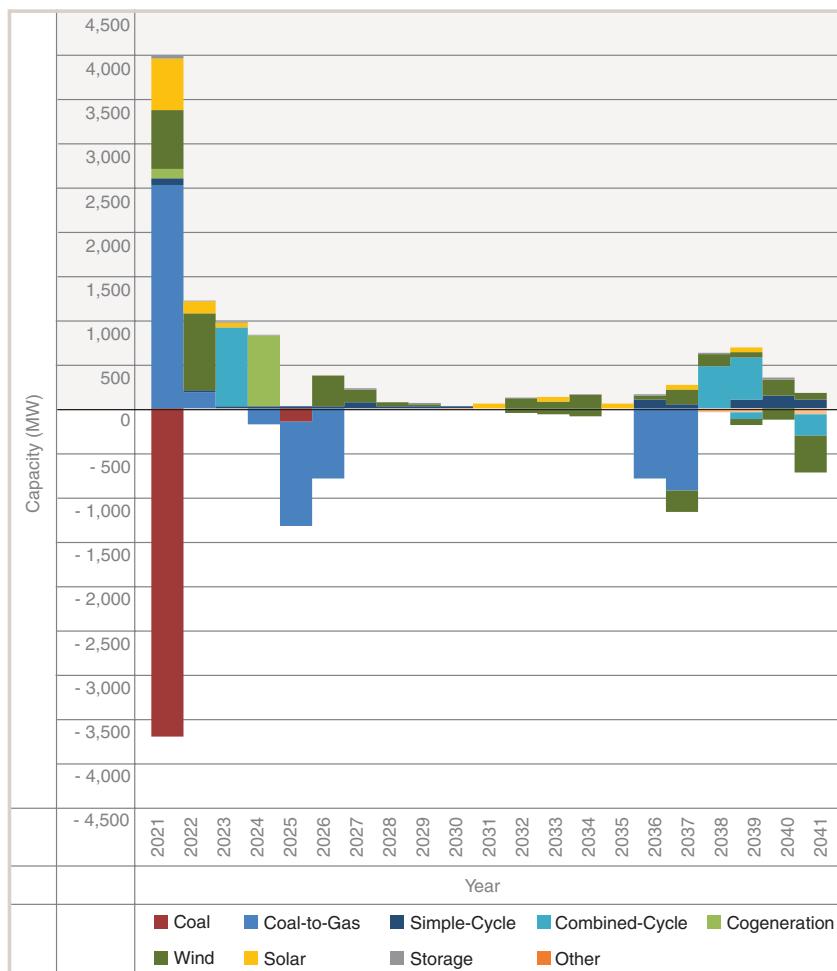
Generation development is lower for the Stagnant Global Oil and Gas Demand scenario compared to the Reference Case. The scenario assumes a lower gas price, less renewable corporate PPAs, earlier coal-to-gas retirements and fewer new cogeneration builds. The natural gas price is based on the AER's low AECO-C natural gas price forecast.³⁰ The lack of load growth expedites the retirement of coal-to-gas converted boilers, as the units cannot fully recover their fixed operating costs. Near-term projects are the same as the Reference Case, and the large-scale near-term combined-cycle and cogeneration projects put additional pressure on coal-to-gas capacity in the 2020s. Aside from specifically identified units that meet the project inclusion criteria, there are no new cogeneration facilities in this scenario, as hydrocarbon markets do not support new investment in the sector.

Generation results

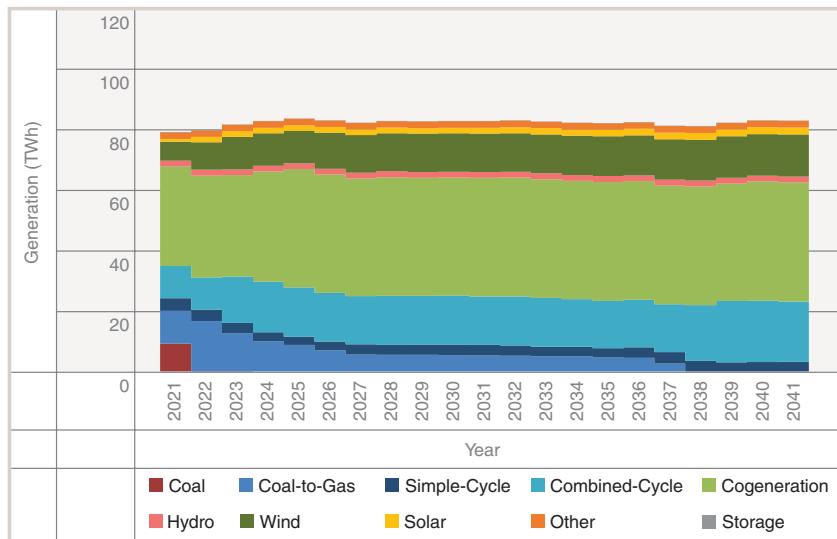
The Stagnant Global Oil and Gas Demand scenario represents a future without a need for significant growth-driven generation capacity. Most of the new generation in this scenario replaces retiring generation. Simple-cycle and combined-cycle replaces retiring coal-to-gas in the 2030s. Combined-cycle growth remains lower than the Reference Case, with two new units, comprising 958 MW of capacity, expected to come online in the late 2030s. Simple-cycle development sees an increase relative to the Reference Case due to coal-to-gas units retiring earlier. Renewable generation additions are lower in this scenario, with 2,377 MW of incremental wind and 1,018 MW of solar added throughout the long-term forecast.

The 2021 LTO scenarios, the Stagnant Global Oil and Gas Demand scenario produces an inverse-U shape load forecast, whereby forecast values increase slowly after 2021 but gradually decrease after reaching a peak in the mid-2020s. The compound average growth rate is 0.1 per cent per year from 2021 to 2041.

³⁰ See AER ST98 report, <https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98/prices-and-capital-expenditure/natural-gas-prices/aeco-c-price>

FIGURE 28: Stagnant Global Oil and Gas Demand: Alberta Generation Additions and Retirements

The Stagnant Global Oil and Gas Demand scenario results in similar generation mix as the Reference Case. However, the reduced demand in the scenario requires 9.2 TWh less generation than the Reference Case by the end of the forecast period.

FIGURE 29: Stagnant Global Oil and Gas Demand Scenario: Alberta Generation

5.0 Additional Insights

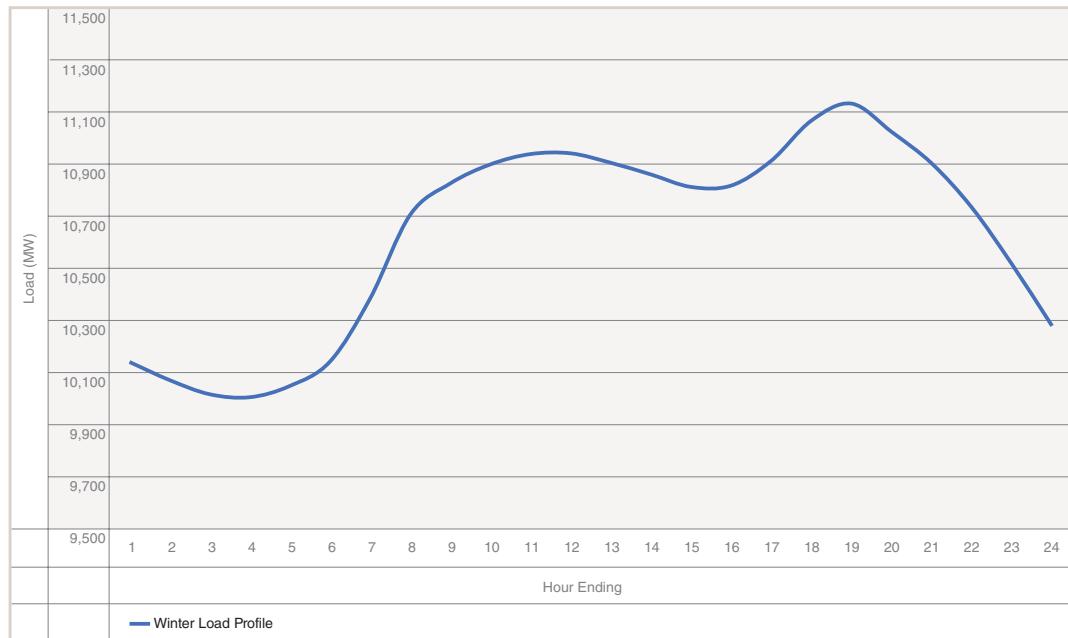
5.1 ADDITIONAL INSIGHTS

The 2021 LTO includes additional insights into areas of analysis that were not traditionally published in previous LTO reports. These incremental insights leverage the different scenarios to address topics of interest that have been raised by stakeholders or that the AESO considers valuable to the multi-faceted discussions around the transformation of the electricity sector in Alberta. These topics include typical consumption patterns, system load, carbon dioxide (CO₂) emissions and resource adequacy.

5.1.1 Typical Consumption Patterns

The 2021 LTO provides a glimpse into the transformation impacting in Alberta's electricity sector over the next two decades. Traditionally, the typical daily AIL shape has followed a relatively stable pattern, characterized by a steep morning ramp driven by Albertans' daily activities (e.g., preparing breakfast, starting business hours, school schedules) and load peaks in the later afternoon hours (usually when Albertans' prepare and consume dinner at home or at restaurants, while malls and other commercial activities are open, and street and security lights come on). Once Alberta households and business wind down in the evening hours, the remaining load is dominated by industrial activities that generally operate 24/7.

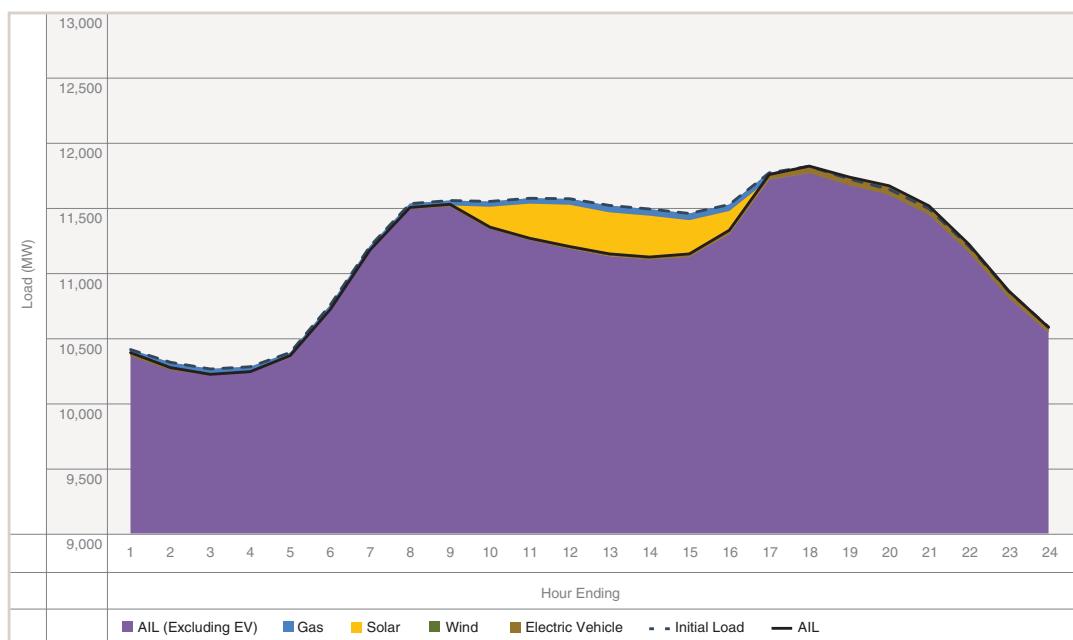
FIGURE 30: Typical Winter Load Profile in Alberta in 2021



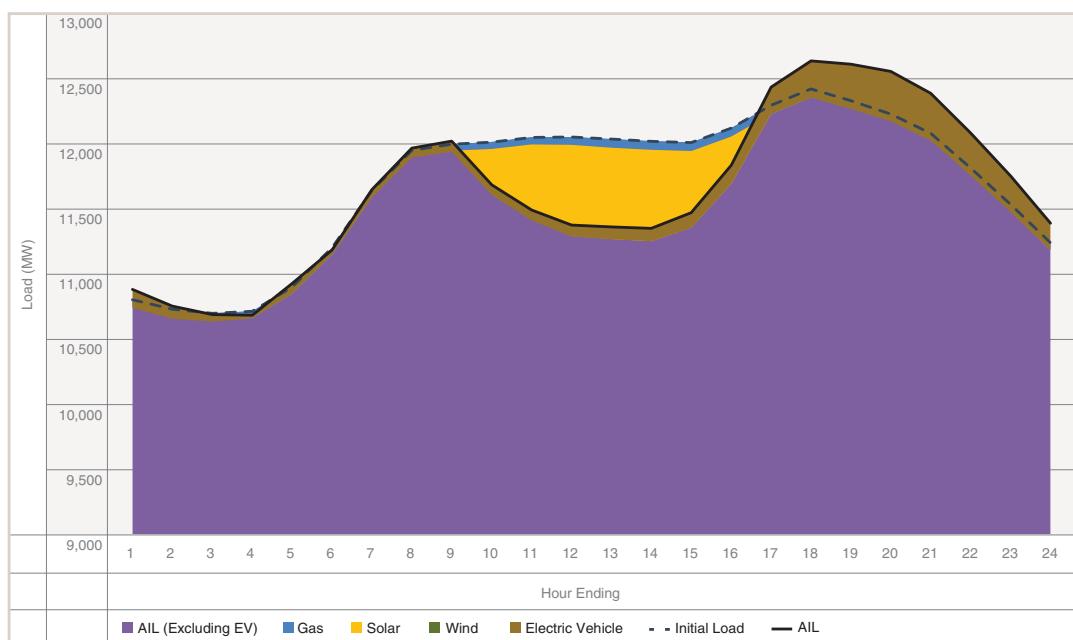
As Albertans drive an increasing number of electric vehicles and install DER technologies, particularly rooftop solar panels, the daily load profile served by grid-connected generation is expected to change. Due to its resemblance to a duck, this emerging daily shape is generally known as the “duck curve”. The duck curve in the Reference Case portrays a future in which solar DER generation is expected to serve Albertans' energy needs on days with sunny and clear-sky conditions and thus lower supply needed from the grid during daylight hours by 2031. By 2041, the combination of increased amounts of solar DER penetration and EV charging are expected to lower load during the mid-day hours and shift traditional peaking conditions from late afternoon hours to well into the evening hours. The penetration of non-solar DER (e.g., wind and gas facilities that are under five MW in size) is expected to have a limited impact to the overall AIL daily profile due to their relatively smaller penetration levels.

FIGURE 31: Typical winter load profiles in 2031 and 2041 in the Reference Case

A Winter Day in 2031



A Winter Day in 2041

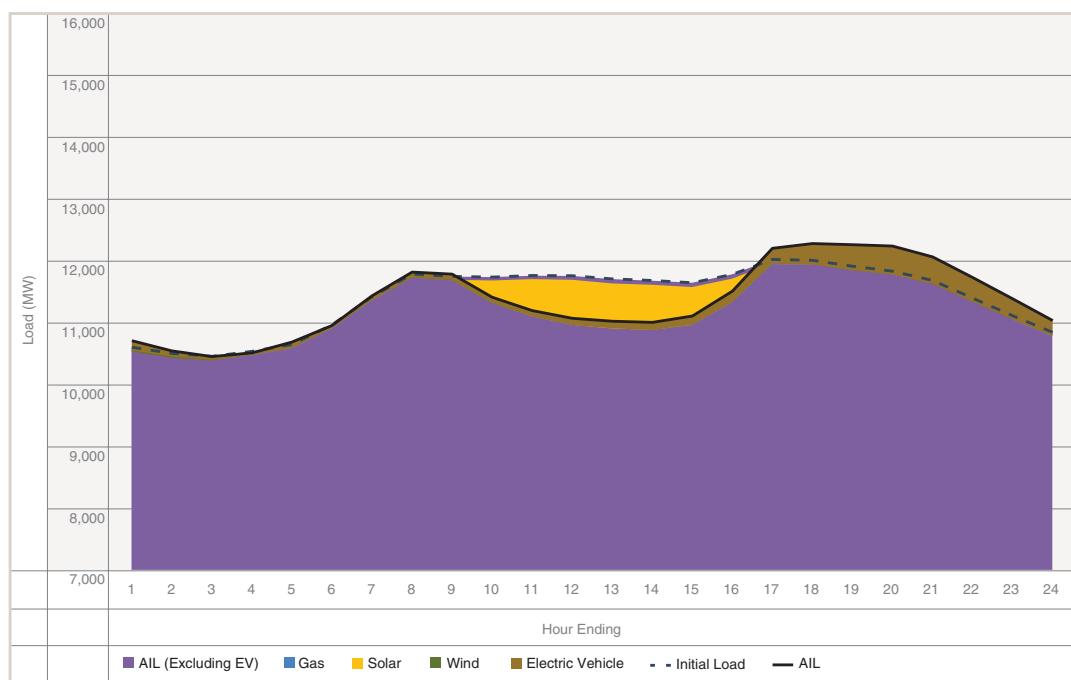


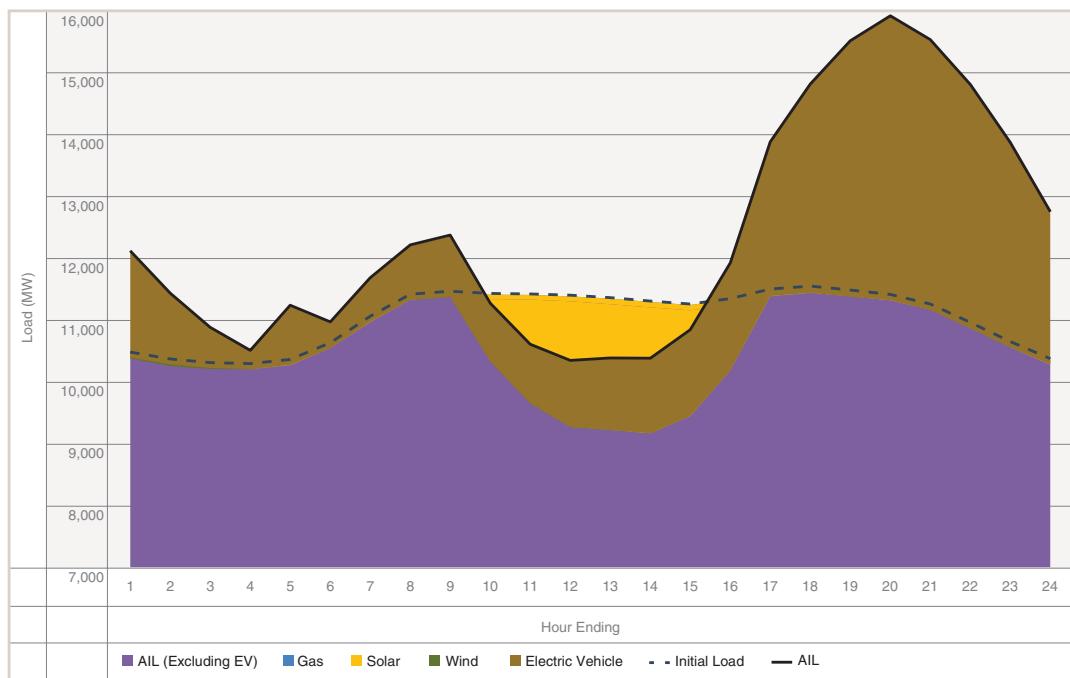
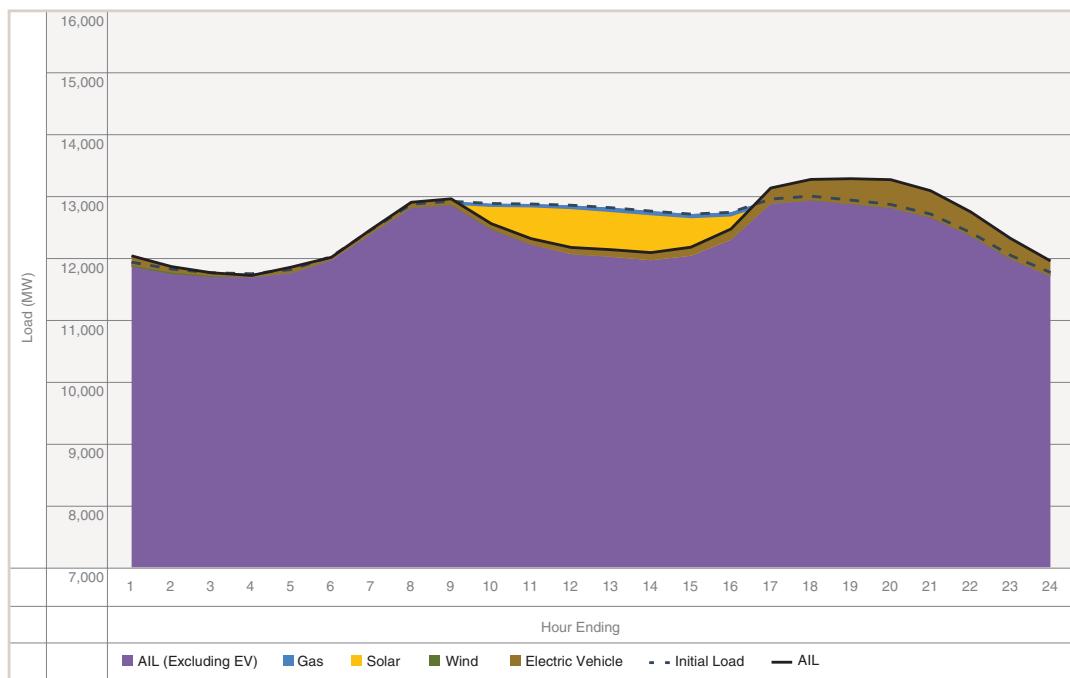
The Clean-Tech scenario results depicts daily load profiles with more ramping than usual as peaking and minimum load conditions will become more frequent and load ramps steeper compared to the Reference Case. For example a typical winter day in 2041, where there is a potential for dual-peaking conditions. The first peak is expected to occur with the morning ramp up and will dissipate once rooftop solar output increases and sunlight remains strong through the afternoon hours. The second peak is expected to take place in the evening hours when EV charging coincides with traditional residential and commercial loads, and rooftop solar output subsides. In addition to dual peaks, dual troughs are also expected to occur during the traditional early morning hours as well as in the middle of the day – the latter caused by maximum solar output.

The Robust Global Oil and Gas Demand and the Stagnant Global Oil and Gas Demand scenarios show similar duck curve results to the Reference Case. This is because the DER and electric vehicle assumptions are the same across these three scenarios.

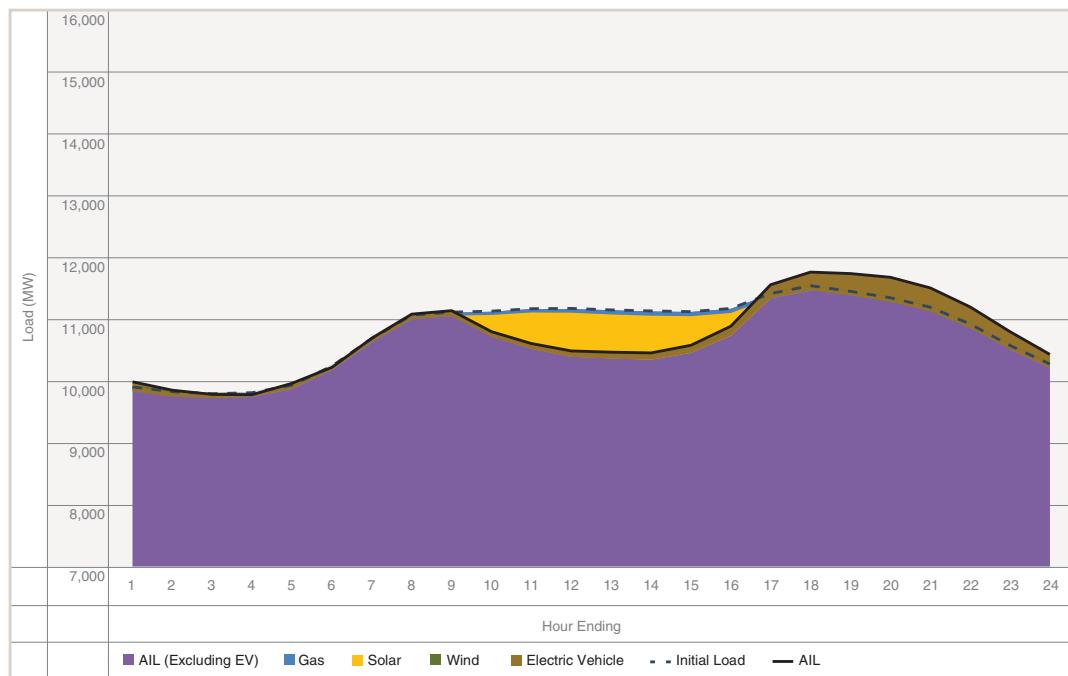
FIGURE 32: Typical Winter Day Load Profile in 2041

Reference Case



Clean-Tech**Robust Global Oil and Gas Demand**

Stagnant Global Oil and Gas Demand



Changes to the typical daily shape of consumption may introduce additional ramping and flexibility concerns to the operability of the Alberta grid. In 2020, the AESO released its first *System Flexibility Assessment* report reviewing needs and capabilities from 2021 to 2030, based on the 2019 LTO projections. In that assessment, the AESO did not identify any emerging needs for immediate system flexibility enhancements.³¹ The AESO remains committed to assessing system flexibility including updating the system flexibility assessment to evaluate the 2021 LTO results, which is expected to be publicly released in 2022.

5.1.2 System Load

System load represents the total electric energy billed to transmission consumers in Alberta and Fort Nelson (British Columbia)³², plus transmission losses. System load differs from AIL, the key measure of load used in the 2021 LTO forecast, by subtracting load that is not delivered through the transmission system. This subtracted load is commonly referred to as BTF load. BTF load is generally served, partially or completely, by on-site generation (or BTF generation). BTF load and generation sites are traditionally industrial sites, primarily composed of large oil sands and petrochemical facilities (which are often configured as cogeneration facilities), a few but not all distribution-connected generation, large university campuses, and the City of Medicine Hat.

Since 2010, BTF load has steadily increased in Alberta due to a combination of factors. Some industrial sites need steam for their production processes. When an electricity generator is used to create steam, the electricity is a byproduct which can be used internally and, if there is any in surplus, for export to the grid. This makes a BTF configuration more economically attractive.

³¹ See AESO's System Flexibility Assessment (2020); URL: <https://www.aeso.ca/assets/Uploads/AESO-2020-System-Flexibility-Assessment-FINAL-jul-17.pdf>

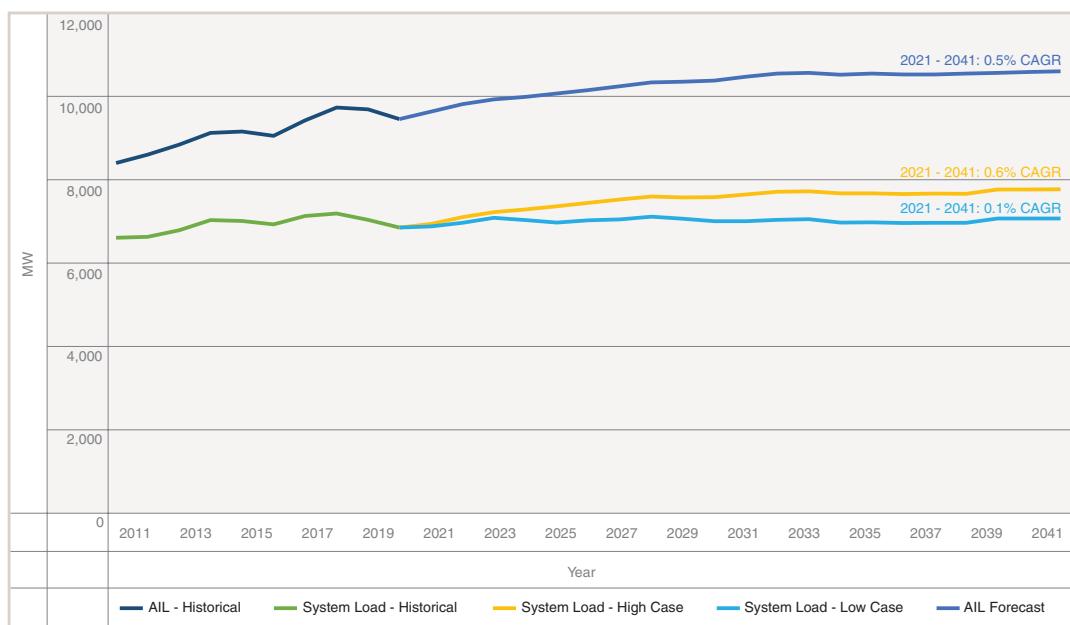
³² For system access service provided in accordance with the ISO tariff under Rates DTS, FTS, and DOS.

The increase of distribution-connected generation, driven by incentives from distribution tariffs and/or policy framework, combined with corporate PPAs, has propelled renewables BTF generation. However, the recent Alberta Utilities Commission (AUC) Decision 26090-D01-2021 will eliminate distribution-connected generation credits, which may put pressure on some of the distribution-connected projects. Finally, growth in the City of Medicine Hat, spurred by commercial activities, such as cryptocurrency mining plus general population and economic growth, has also led to higher BTF load growth. The key drivers of BTF load are unique to each case and broad generalizations of how these factors may affect future BTF load growth should be limited and assessed with caution.

Given the uncertainty of factors driving future BTF load and generation, the 2021 LTO includes two sensitivity cases of the system load forecast. These two cases were developed after analyzing historical load and generation operations at existing sites by technology (gas, solar, wind). The high system load case assumes that BTF load is only partially met by BTF generation and the remainder needs to be served by grid-supplied generation. The low system load case assumes that load is mostly matched by on-site generation and that the need for grid-supplied generation is limited. These sensitivities are applied to all the 2021 LTO scenarios.

The following graph displays a comparison of the forecast system load and AIL under the Reference Case. In the high-system load scenario, system load is expected to grow at a slightly faster pace than the AIL, at 0.6 per cent compound rate annually. In the low-system load scenario, system load is expected to grow at a slower rate than the AIL, at 0.1 per cent as additional BTF generation is built and assumed to serve on-site load.

FIGURE 33: Average System Load and AIL, Reference Case



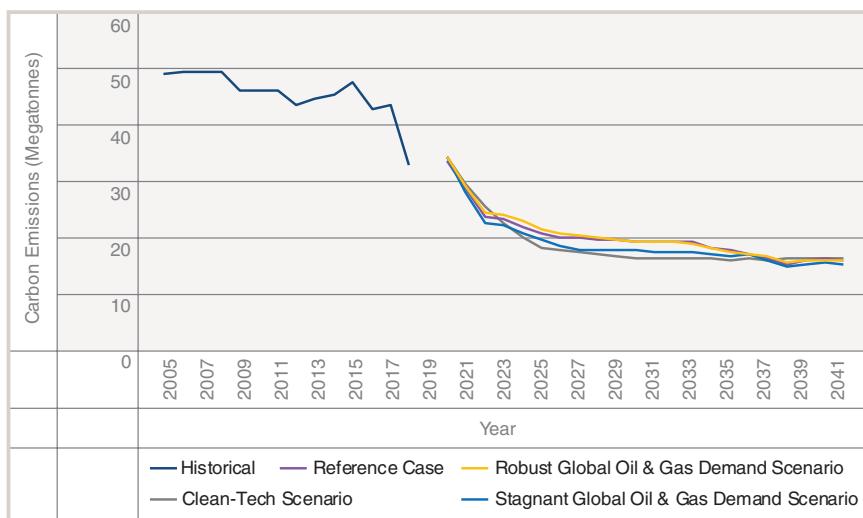
5.1.3 CO₂ Emissions

The Reference Case and each of the scenarios demonstrates a large reduction in Alberta's electricity sector carbon emissions, the result of 15 years of increasingly stringent carbon emissions regulation and pricing. In addition to carbon pricing, the Government of Alberta and the Government of Canada have legislated strict regulations to end coal-fired generation. Carbon pricing aside, coal generation capital costs have while renewables generation capital costs have decreased, creating an environment where the economics of new coal generation were subordinated by natural gas generation and renewables generation in the province. Alberta has transitioned from a predominantly coal-based fleet to a largely natural gas-fired fleet over the past two decades, and the 2021 LTO projects a continued trend of decarbonization in the electricity sector. Coal-to-gas conversions enable thermal producers to redeploy existing capital in a lower carbon configuration, contributing to a meaningful emissions reduction in the near-term. Renewables penetration is forecast to continue with growth in wind and solar generation, and high-efficiency natural gas-fired generation is expected to make up a significant portion of the future firm generation capacity in the reference case. As a result of changing economics, driven largely by government policy and technological advancements, emissions from Alberta's electricity generation are expected to decline in the future.

The Reference Case forecasts a decline in Alberta's electricity sector emissions of 61 per cent from 2005 levels by 2030, and a decline of 67 per cent by 2040. Alberta's electricity sector is forecast to reduce its carbon emissions by 41 per cent from 2005 levels by the end of 2021, primarily as a result of the shut-down and natural gas conversion of coal power plants. Additional renewables generation simultaneously contributes to the large reduction in sectoral greenhouse gas emissions.

The carbon emissions reduction in the Clean-Tech scenario represents a dramatic reduction relative to carbon output from Alberta's historical generation fleet. Increased generation from high-efficiency natural gas generation, renewables generation, and storage contribute to the reduced carbon intensity of the grid, whereas the retirement of carbon-intensive coal and coal-to-gas boiler generators leads to a lower emissions scenario. The expected emissions from the electricity sector are 16.4 mega-tonnes in 2030 and 16.1 mega-tonnes in 2040. This represents a forecast emissions reduction of 66 per cent by 2030, based on 2005 electricity sector emissions in Alberta.

Although the Robust Global Oil and Gas Demand scenario results relatively low sectoral emissions compared to the scenarios, the result is substantially driven by the categorization of cogeneration emissions. Many cogeneration operations are categorized as emissions related to the primary sectors that the facilities service – for example, raw bitumen extraction rather than electricity production. The approach is consistent with the Government of Canada's Greenhouse Gas Reporting Program (GHGRP) – Facility Greenhouse Gas (GHG) Data.

FIGURE 34: Alberta Electricity Sector Emissions by Scenario

Although not contemplated in the 2021 LTO, there are other potential activities that may achieve additional carbon emissions reductions. Some of these activities include Carbon Capture, Utilization and Storage (CCUS), introducing hydrogen as a component of the natural gas fuel supply, and the introduction of Small Modular Reactors (SMRs) into the supply mix. The AESO will continue to monitor and update stakeholders on developments within these and other emerging technology areas.

5.1.4 Resource Adequacy

The AESO uses a model to assess resource adequacy for set years within the 2021 LTO to evaluate the Reference Case and the various additional scenarios. The 2021 LTO has adjusted its methodology to guide new additions based on economics; the 2021 model does not use a reserve margin target as a build signal as in prior LTOs. Based on this, the AESO determined it is productive and informative to further evaluate the risk of unserved energy using the specific load forecast and generation build associated with the 2021 LTO Reference Case and each scenario. Where risks were identified, the AESO ran sensitivity analyses to assess factors or measures that would mitigate such risks; these sensitivities were performed by changing key assumptions (e.g., shifting build timelines of generation assets, modifying EV charging profiles, increasing energy storage penetration). The AESO selected the years 2026, 2031 and 2036 for assessment to ensure a full balanced view of the forecast horizon. The Resource Adequacy Model (RAM) determines the tradeoff between capacity (MW) and reliability (expected unserved energy MWh) using a probabilistic approach that varies load and generation. The results are measured against the Long-Term Adequacy Threshold as outlined in section 202.6 (5) of the ISO rules, Adequacy of Supply.

The AESO utilizes the Strategic Energy and Risk Valuation Model (SERVM) software to house its RAM. SERVM is an electric system risk model used for resource adequacy studies. It conducts hourly chronological simulations which model a full distribution of weather years that impact both load and intermittent renewables resources to account for load and intermittent renewable output uncertainty. The model also includes a Monte Carlo simulation for generator outages to provide a full distribution of physical reliability metric (expected unserved energy) outcomes.

For a given resource mix defined within the model, the AESO runs 7,500 different annual hourly chronological supply availability assessments (8,760-hour simulations). The 7,500 iterations are made up of 30 weather years (load and renewable profiles), five load forecast economic scenarios and 50 unit forced outage draws to capture frequency and duration of forced 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. Due to the infrequency of resource adequacy driven reliability events in Alberta, it is important to review the underlying drivers of historical reliability events and ensure that the key drivers are represented in the RAM.

5.1.4.1 Reference Case

For the reference case the results show little to no risk of unserved energy during the early-to-mid-forecast period. Even accounting for weather and economic uncertainty, the reference case generation build shows more than sufficient capacity value to account for the range of anticipated load outcomes. Later in the forecast period the results show an elevated risk of expected unserved energy, though as the sensitivities show this is attributed to timing issues around generation retirement and subsequent replacement. There are generally sufficient resources overall, but the changes to the generation mix are dynamic and determining the exact timing of entry and exit in the late forecast period is challenging. Overall, the results show this is something that will be monitored but is not an immediate concern, being so late in the forecast period. The AESO would expect that market signals closer to this time period would result in more refined timing of new unit entry and retirement such that the supply adequacy risk was minimized.

TABLE 7: Reference Case Resource Adequacy Results

EUE - MWh (Threshold)	2026 (1,014)	2031 (1,046)	2036 (1,050)	Summary
Reference Case				<ul style="list-style-type: none"> Reference Case shows no issues in 2026 and 2031 Issues in 2036 are primarily due to timing of new firm capacity replacement
RC + CC1				<ul style="list-style-type: none"> Moving the current generic combined-cycle that builds in 2037 to 2036
RC + CC2				<ul style="list-style-type: none"> Moving an additional generic combined-cycle that builds in 2039 to 2036

Note: the threshold is based on the AESO supply adequacy expected unserved energy metric threshold (as per ISO Rule 202.6). The **green** circles represent RAM results that are well under the threshold, **orange** circles represent results within +/- 50 per cent of threshold, and **red** circle represent results exceeding the threshold by more than 50 per cent.

5.1.4.2 Clean-Tech

For Clean-Tech scenario, the results show little to no risk of unserved energy during the early forecast period. In the near-term, accounting for weather and economic uncertainty, the Clean-Tech scenario resource build provides enough capacity value. However, with large capacity retirements and a strong increase in demand from electric vehicles by 2031, the RAM shows higher risk to resource adequacy that then increases through the forecast period. Sensitivities show in the mid-forecast period the lack of generation capacity is the driver of the risk, while in the later portion of the forecast, it is assumptions around electric vehicle charging profiles and penetration that account for the increased risk in expected unserved energy (EUE). There is a high degree of uncertainty around how future charging profiles will evolve; as the system observes increasing penetration of electric vehicles, these sensitivities are meant to test a range of outcomes. These results show a number of risk factors that should be monitored and reviewed as the energy system adapts to the many potential changes. In particular, the results indicate a sensitivity to the daily shape of charging for EVs as an area to monitor.

TABLE 8: Clean-Tech Resource Adequacy Results

EUE - MWh (Threshold)	2026 (1,011)	2031 (1,022)	2036 (1,034)	Summary
Clean Tech				<ul style="list-style-type: none"> Clean-Tech shows no issues in 2026 Issues in 2031 show the risk of early retirements leading to insufficient firm capacity Issues in 2036 are primarily due to EV penetration and charging assumptions and a lack of new firm capacity replacement
CT + EVU				<ul style="list-style-type: none"> Adjusting the daily charging profile of the electric vehicle additions while maintaining total energy requirements Electric Vehicle charging assumptions are modified to represent time of use charging behaviour to flatten the charging profile and incent a shift of peak charging to expected lower priced hours
CT + CC				<ul style="list-style-type: none"> Adding a firm capacity generic combined-cycle in 2030 (approximately 480 MW)
CT + EVU + CC				<ul style="list-style-type: none"> Adjusting the daily charging profile of the electric vehicle additions while maintaining total energy requirements Adding a firm capacity generic combined-cycle in 2030 (approximately 480 MW)
CT + EVU + Storage				<ul style="list-style-type: none"> Adjusting the daily charging profile of the electric vehicle additions while maintaining total energy requirements Increasing currently assumed storage capacity by 50 per cent within the scenario (approximately 600 MW)

Note: the threshold is based on the AESO supply adequacy expected unserved energy metric threshold (as per ISO Rule 202.6). The **green** circles represent RAM results that are well under the threshold, **orange** circles represent results within +/- 50 per cent of threshold, and **red** circle represent results exceeding the threshold by more than 50 per cent.

5.1.4.3 Robust Global Oil and Gas Demand Scenario

For the Robust Global Oil and Gas Demand scenario, the results show little to no risk of unserved energy during the early-to mid-forecast period. The RAM shows sufficient capacity value to account for the range of anticipated load outcomes. Late in the forecast period, the outcomes show an elevated risk of expected unserved energy, though as the sensitivities show, this is attributed to timing issues around generation retirement and subsequent replacement. Generally, there are sufficient resources overall, but the changes to the generation mix are dynamic and determining the exact timing of entry and exit in the late forecast period is challenging. Much like the Reference Case overall, the results show this is something that will be monitored but not a concern so late in the forecast period.

TABLE 9: Robust Global Oil and Gas Demand Scenario Resource Adequacy Results

EUE - MWh (Threshold)	2026 (1,042)	2031 (1,100)	2036 (1,132)	Summary
Robust Global Oil and Gas Demand				<ul style="list-style-type: none"> The scenario shows no issues in 2026 and 2031. Issues in 2036 are primarily due to timing of new firm capacity replacement.
RO + CC1				<ul style="list-style-type: none"> Moving a current generic combined-cycle that builds in 2037 to 2036 (approximately 480 MW)
RO + CC2				<ul style="list-style-type: none"> Moving an additional generic combined-cycle that builds in 2037 to 2036 (approximately 480 MW)

Note: the threshold is based on the AESO supply adequacy expected unserved energy metric threshold (as per ISO Rule 202.6). The **green** circles represent RAM results that are well under the threshold, **orange** circles represent results within +/- 50 per cent of threshold, and **red** circle represent results exceeding the threshold by more than 50 per cent.

5.1.4.4 Stagnant Global Oil and Gas Demand Scenario

The Stagnant Global Oil and Gas Demand scenario results show low risk of unserved energy during the early forecast period. The RAM shows sufficient capacity value to account for the range of anticipated load outcomes. In the mid-and late forecast period, the outcomes show an elevated risk of expected unserved energy, though as the sensitivities show this is attributed to timing issues around generation retirement in the midterm and subsequent replacement in the longterm. Generally, there is insufficient firm capacity, but the changes to the generation mix are dynamic and determining the exact timing of entry and exit in the late forecast period is challenging. Much like the Reference Case overall, the results show this is something that will be monitored but not a concern for the forecast period. As with the Reference Case and Robust Global Oil and Gas Demand Scenarios, it is expected that market signals will drive more refined timing of new entry and retirement closer to the time periods involved.

TABLE 10: Stagnant Global Oil and Gas Demand Resource Adequacy Results

EUE - MWh (Threshold)	2026 (987)	2031 (987)	2036 (969)	Summary
Stagnant Oil and Gas Demand				<ul style="list-style-type: none"> The scenario shows no issues in 2026 Issues in 2031 shows the risk of early retirements leading to insufficient firm capacity Issues in 2036 are primarily due to timing of new firm capacity replacement
SO + CC1				<ul style="list-style-type: none"> Moving the current generic combined-cycle that builds in 2039 to 2030 (approximately 480 MW) brings results in both years below the threshold value, extending the life of assumed retirement assets would directionally do the same

Note: the threshold is based on the AESO supply adequacy expected unserved energy metric threshold (as per ISO Rule 202.6). The **green** circles represent RAM results that are well under the threshold, **orange** circles represent results within +/- 50 per cent of threshold, and **red** circle represent results exceeding the threshold by more than 50 per cent.

Overall, in the near and mid-term the AESO sees limited risk of unserved energy. The various scenarios and sensitivities show that long-term forecast assumptions contain significant uncertainty and should be monitored and appraised based on how the energy transition, technological and regulatory parameters shift over time. One example highlighted here – the transition to electric vehicles and associated market penetration, technological advancement and regulatory framework – leads to significant uncertainty around eventual electrical consumption patterns. The AESO will continue to observe, review, assess and communicate with stakeholders of the implications of changes to these and other parameters as better information becomes available.

The reader must interpret the reliability results for the years 2031 and 2036 with caution. The sensitivity cases indicate that supply adequacy modeling for periods further out can be significantly impacted by relatively minor changes in fundamental inputs. Given that no immediate risks were identified, the AESO concludes that the risk drivers identified by the modelling can be monitored while providing sufficient time to further mitigate risks should they become more certain.

6.0 Appendix

6.1 LEVELIZED COST OF ENERGY

Levelized Cost of Energy (LCOE) is the average cost per megawatt hour of energy to recover all capital and operating costs, including a specified rate of return, over the entire life of a power generation project. The following assumptions were used in the calculation of the LCOE and represent the cost input assumptions used in the generation forecasting modelling of the 2021 LTO scenarios. These assumption focus on generic merchant generation technologies (simple cycle, combined cycle, wind and solar); cogeneration is excluded representative cost estimates can range widely given how this technology is site-specific and dependent on steam host characteristics.

6.1.1 Technology Specific Cost Assumptions in 2021 Dollars

TABLE 1: Technology Specific Cost Assumptions in 2021 Dollars

Facility Type	Simple cycle aero derivative gas turbine (2x0)	Combined-cycle (with duct firing) (1x1)	Wind generation facility (2021-2025)	Solar generation facility (2021-2025)	Wind generation facility (2026-2030)	Solar generation facility (2026-2030)
Size (MW)	93	479	100	50	100	50
Overnight Capital Cost (\$/kW AC)	1,159	1,667	1,586	1,643	1,105	1,388
Fixed Operating & Maintenance Costs (\$/kw/year)	57.30	53.90	32.50	31.85	29.25	31.85
Variable Operating & Maintenance Costs (\$/MWh)	4.60	2.70	0.00	0.00	0.00	0.00
Capacity Factor (%)	35%	76%	40%	21%	40%	21%
Heat Rate (GJ/MWh)	9.68	7.03	N/A	N/A	N/A	N/A
Natural Gas Price Range (\$nominal/GJ)	2.30-4.02	2.30-4.43	N/A	N/A	N/A	N/A
Expected economic life (years)	25	30	25	25	25	25

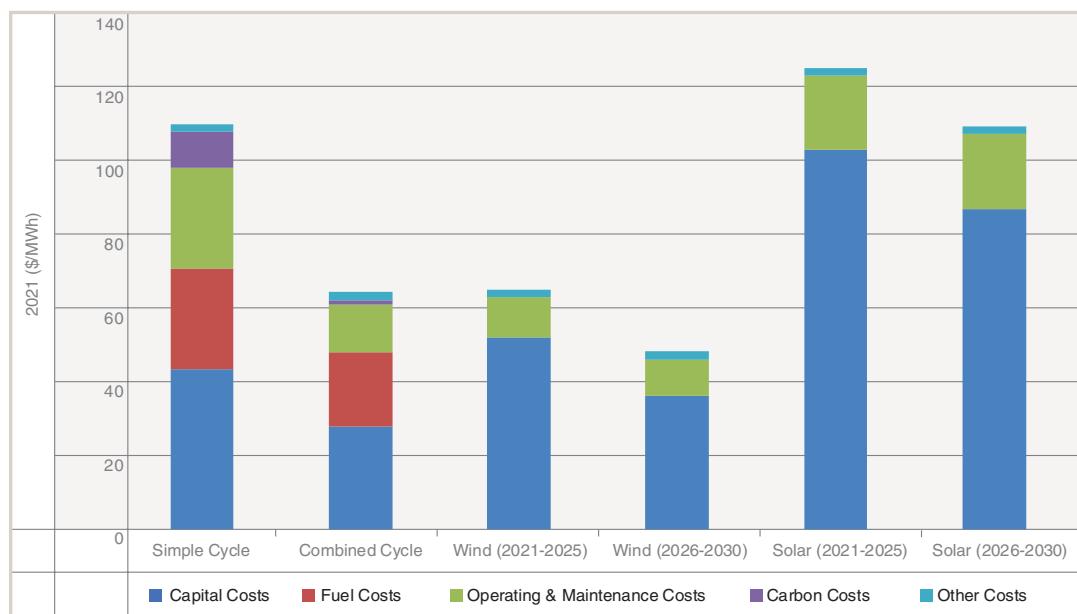
6.1.2 Common Assumptions For All Technologies

LCOE analysis assumes that all plants are financed 50 per cent by debt and 50 per cent by equity, and the debt-to-equity-ratio is held constant during the project life. It is assumed that the projects have a six per cent cost of debt and a 15 per cent cost of equity, resulting in a pre-tax weighted average cost of capital (WACC) of 10.5 per cent for a merchant project. Sensitivities on the WACC demonstrate that lower-risk, fully contracted projects may accept lower project returns and have a lower LCOE.

In line with the Reference Case, the LCOE calculations assume a carbon price of \$40-per-tonne in 2021 and \$50-per-tonne in 2022 and an increase of two per cent annually thereafter. It is assumed that gas units are benchmarked against the current TIER Regulation's CO₂ emission standard of 0.37 t/MWh in all years. In this analysis, the LCOE for wind and solar does not consider any revenue from carbon offsets or carbon credits. In the Figure 2 of this appendix, the impact of the carbon price and policy on the different technologies is illustrated.

Other cost assumptions include a transmission loss factor of 2.8 per cent, a trading charge of \$0.382 per MWh and a commodity fuel charge of 1.76 per cent of gas prices. A general inflation rate of two per cent is assumed.

FIGURE 1: Levelized Cost of Energy



The results show that within the technologies considered in this analysis, wind and combined-cycle are the most cost-competitive technologies, and solar and simple-cycle are the least cost-competitive technologies. Capital costs, including return on capital, are the largest component of the LCOE for all of the technologies examined.

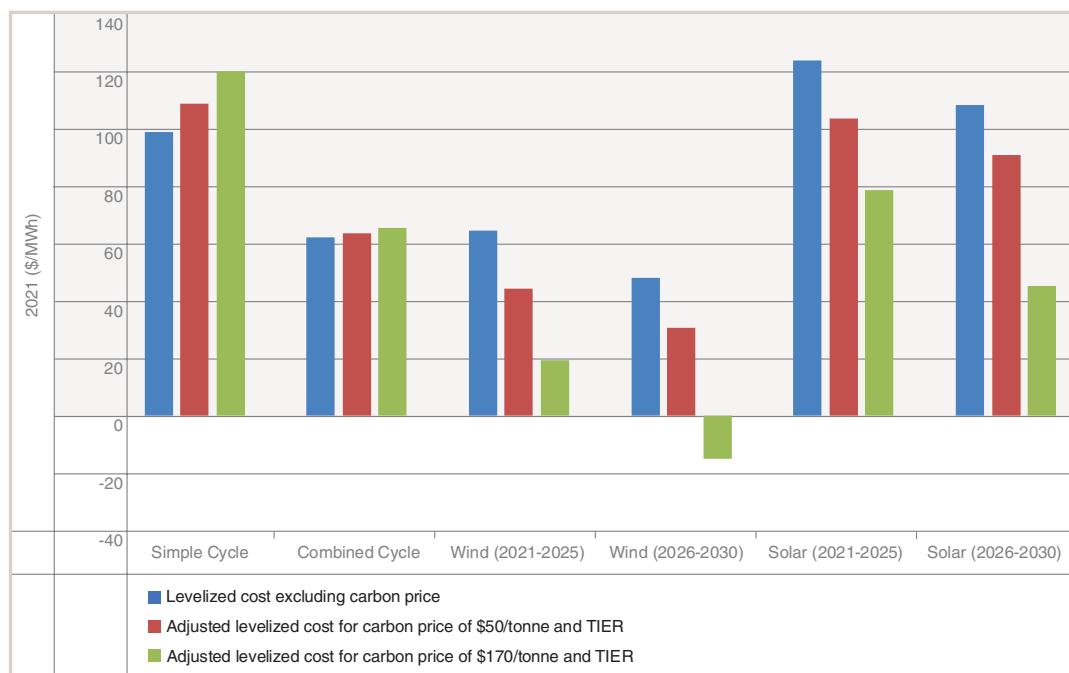
Impact of Carbon Policy on LCOE

Carbon price and policy impact the LCOE for thermal units and provide additional revenue sources for renewable technologies. Table 2 and Figure 2 below illustrate how carbon price and policy can impact the LCOE of different generation technologies.

TABLE 2: Descriptions of Carbon Policy Sensitivities

	Levelized cost at carbon price of \$50-per-tonne and TIER	Levelized cost of carbon prices at \$170-per-tonne and TIER
Carbon Price Assumption	<ul style="list-style-type: none"> Carbon price of \$40-per-tonne in 2021, increasing to \$50-per-tonne in 2022, and escalating at two per cent thereafter 	<ul style="list-style-type: none"> Carbon price of \$40-per-tonne in 2021, increasing to \$50-per-tonne in 2022 Subsequently carbon price increase by \$15-per-tonne per year, reaching \$170-per-tonne by 2030, and escalating at 2% thereafter
Carbon Policy Assumption	<ul style="list-style-type: none"> TIER with benchmark of 0.37t/MWh Renewables can create Offsets or EPCs 	<ul style="list-style-type: none"> TIER with benchmark of 0.37t/MWh Renewables can create Offsets or EPCs

FIGURE 2: Impact of Carbon Price



In a scenario where carbon prices increase to \$170-per-tonne by 2030, the expected value of offsets is higher than the LCOE, thus making the LCOE a negative value, when adjusted for offset revenues.

The LCOE for combined-cycle technology is not as sensitive as simple-cycle technology to increases in carbon price. This is because the emissions intensity of combined-cycle technology is very close to the high-performance benchmark for electricity prescribed in the TIER regulation.

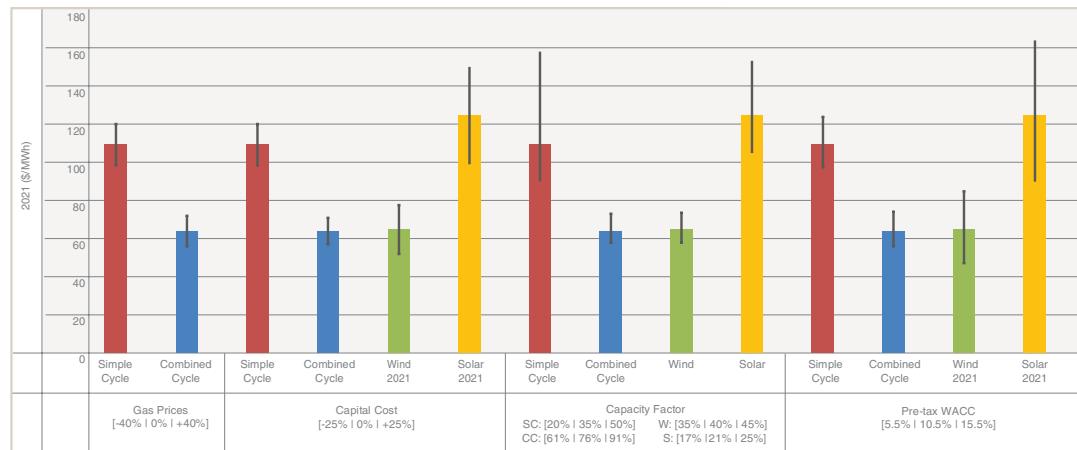
LCOE sensitivities

In order to demonstrate the volatility of the LCOE to diverse project conditions, the following sensitivities were considered:

TABLE 3: LCOE Sensitivity Assumptions by Technology

Assumption change	Simple-cycle	Combined-cycle	Wind-2021	Solar-2021
Natural Gas Price	+ / - 40 %			N/A
Capital Cost	+ / - 25 %			
Capacity Factor	+ / - 15 %		+ / - 5 %	+ / - 4 %
Pre-tax WACC	+ / - 5 %			

FIGURE 3: LCOE Sensitivities Across Technologies





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