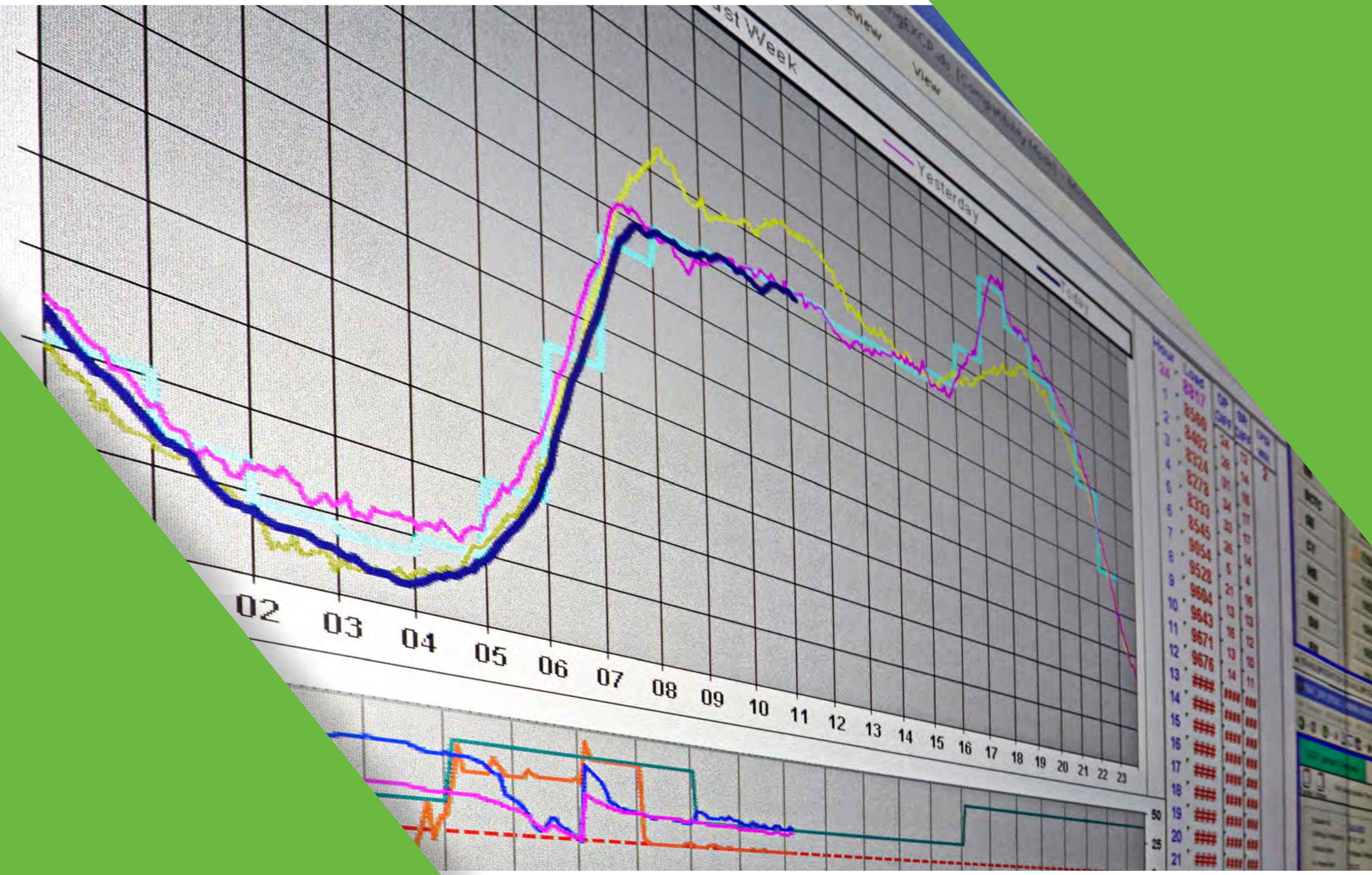

Results

Reference Case

AESO 2024 Long-Term Outlook

MAY 2024

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Overview

- The Reference Case represents the base-case load forecast for the *2024 Long-Term Outlook* (LTO) and will be used as an input to the Reference Case, Decarbonization by 2035 and Alternative Decarbonization generation forecasts. The Reference Case uses the existing energy-only market framework and does not consider any changing market structures.
- Load growth in the near-term is driven mainly by macroeconomic variables (gross domestic product [GDP], employment, population) and the connection of load projects. In the long-term, especially after the 2030s, electricity demand growth is driven by the acceleration of the energy transition which increases electric vehicle (EV) adoption, hydrogen production and electrification of building heating and cooling.
- Factors such as improving energy efficiency and growing adoption of distributed energy resources (DER) play a role in offsetting load.
- Due to the variability of EV charging and building heating and cooling profiles, and, to a lesser extent rooftop solar production, there is more variation in daily hourly load. This variability from EV and building load contributes to a greater increase in peak load compared to average and total load.
- Planned near-term natural gas-fired additions combined with increasing renewable capacity into the 2030s results in increased chances of supply surplus hours into the mid-forecast period.
- Combined-cycle units and cogeneration facilities retrofitting with carbon capture, utilization and storage (CCUS) are expected provide the bulk of electricity generation across the forecast horizon, driven by a combination of provincial and federal investment tax credits.
- Forecast next-of-a-kind declines in capital costs for nuclear small modular reactor (SMR) technology drives the economics of several late-term forecast nuclear SMR baseload additions.

Reference Case

The Reference Case for the LTO is consistent with the provincial government's target to achieve decarbonization by 2050. The Reference Case load forecast projects electricity demand over the next 20 years and considers recent economic conditions and existing regulatory frameworks that impact load.[1] Increasing electrification in the province with regards to the energy transition and decarbonization leads to higher load volatility, which has been smoothed with the integration of load profiles with anticipated managed EV charging to reduce the overall peaks and valleys. The Reference Case load forecast serves as the base-case of the 2024 LTO. In this scenario, the high-performance benchmarks for electricity and hydrogen in the *Technology Innovation and Emissions Reduction* (TIER) *Regulation* reduce to zero by 2050, the TIER fund price increases in alignment with the federal carbon pricing schedule, and the *Clean Electricity Regulations* (CER) are not a binding constraint on Alberta generators. Additionally, generation capital costs are impacted by applicable investment tax credits (ITC).[2] The 2024 LTO is focused on the existing energy-only market framework and does not consider any changing market structures.

[1] For more information on load methodology used in the 2024 LTO, see the Load Methodology section.

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

Load Forecast

The Reference Case load forecast shows Alberta Internal Load (AIL) growth is impacted by several factors. Macroeconomic factors, including the oil sands production outlook, indicate a sustained growth trajectory for Alberta's economy, which in turn drives load growth in the near-term. New load connection projects also reinforce robust short-term load growth. Moreover, the landscape of the energy transition, including electrification of transportation and building sectors and the load growth resulting from an increase in clean hydrogen production, further compounds this development in the long-term, while growth in energy efficiency and behind the fence distributed resources provide some counterbalance.[3]

The 2024 Reference Case results suggest demand growth across the whole province, rather than one distinct area. However, regions with higher population density, particularly Calgary, Edmonton and South regions, are anticipated to experience higher growth compared to industrial-focused regions due to load from EV adoption and electrification of building heating and cooling.[4]

Figure 1 shows the 2024 LTO Reference Case forecast expects higher growth than the Reference Case results of the 2021 LTO.[5] This difference is largely driven by elements of the energy transition including accelerated adoption of EVs and electrification of building heating and cooling, which have a more pronounced long-term effect on load growth in the 2024 LTO. The compound annual growth rate (CAGR) of energy consumption for the forecast period of 2024 to 2043 is 1.2 per cent compared to the 0.4 per cent from 2022 to 2041 in the 2021 LTO.[6] The CAGR of energy consumption for the 2024 LTO is also higher than the Net Zero Emissions Pathways forecasted CAGR of 1.1 per cent from 2022 to 2041.[7]

While stronger load growth is observed in the 2024 LTO when compared to the 2021 LTO, this does not suggest a doubling or tripling of electricity demand by the end of the 20-year forecasting period. The Reference Case 2043 AIL forecast suggests that average hourly load will increase by approximately 26 per cent from 10,117 megawatts (MW) in 2024 to 12,704 MW in 2043. Note there are risks of potential new sources of load for Alberta as the economy evolves with the energy transition through residential, commercial, and industrial electrification that could drive CAGR higher such as data centers, electrification of pipelines and crypto currencies.

[3] For more details on the load methodology in the 2024 LTO, see the Load Forecast Methodology section.

[4] AESO Planning regions and area map can be found in here

[5] AESO 2021 Long-term Outlook can be found here

[6] Note that the full forecast horizon for the 2021 LTO is from 2021 to 2041. AESO 2021 Long-term Outlook can be found here

[7] AESO Net-Zero Emissions Pathway Report can be found here

Figure 1: Reference Case – Average AIL Forecast

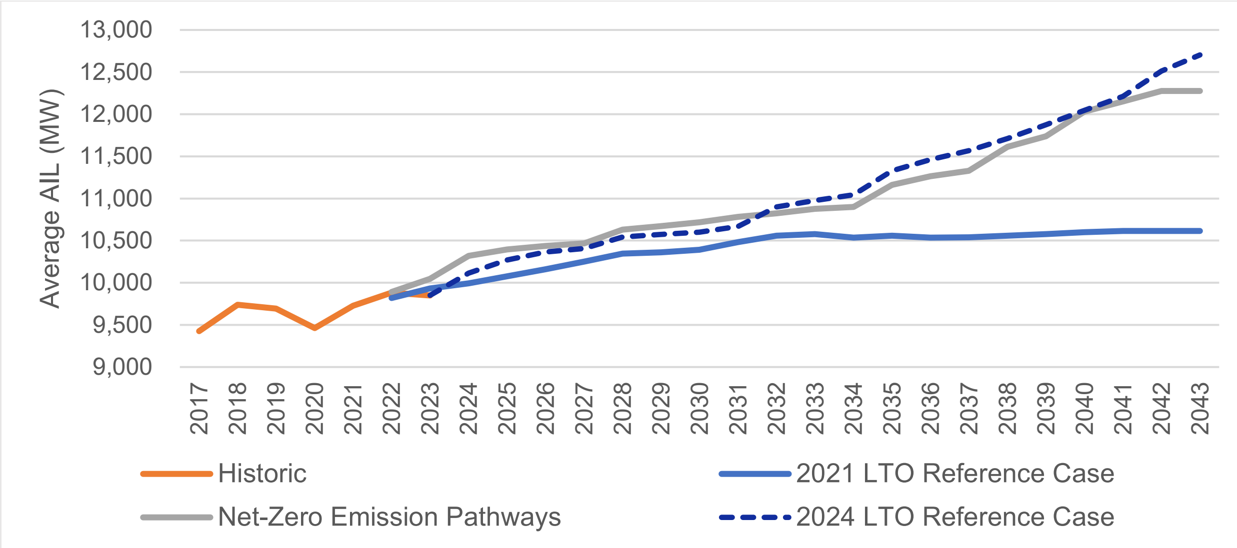
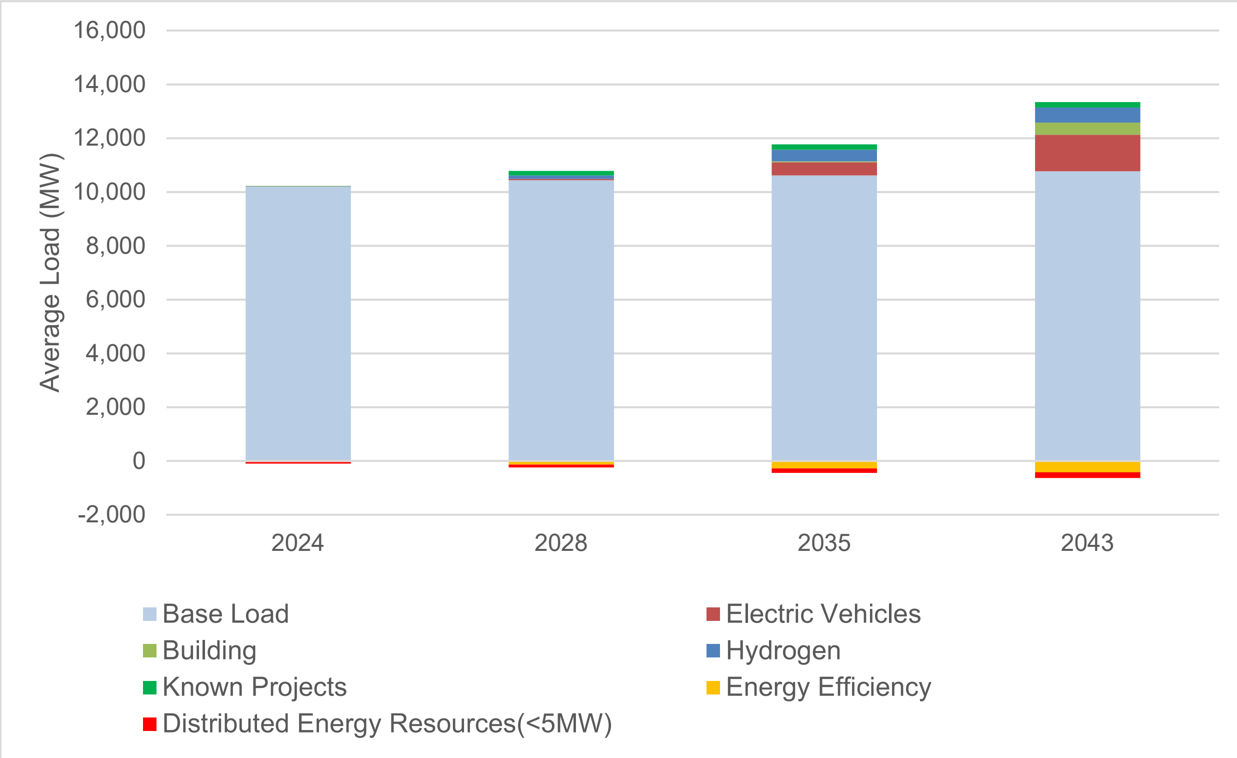


Figure 2 shows the evolving share of each load component in the Reference Case throughout the forecast. The overall load becomes significant in the post-2030s period. As EV adoption accelerates in line with the federal Emissions Reduction Plan (ERP), EV charging load becomes a significant contributor to load growth. This is seen in Figure 2 as EV charging load accounts for nearly 11 per cent of the total load in 2043. While electrification of building heating and cooling experiences relatively slow rates of adoption in the 2020s, as technology improves and electrification accelerates to meet net zero building targets, building load rises significantly from the 2030s into the 2040s. Finally, as demand increases for hydrogen fuel as feedstock for various industrial processes, load is anticipated to grow to support hydrogen production facilities. This is aligned with the governments of Alberta's vision to integrate hydrogen as part of a carbon neutral Alberta in 2050.

Improvement in energy efficiency and increases in DER capacity have a growing offsetting impact on load. The effect of energy efficiency and DERs is seen in Figure 2 represented as negative values. While their impact is relatively small in the 2020s, their influence becomes stronger as they offset a combined average hourly load by 674 MW by 2043, or by 458 MW and 216 MW in 2035 and 2028, respectively.

Figure 2: Reference Case - AIL Composition: Traditional Drivers vs. Additional Load Sectors

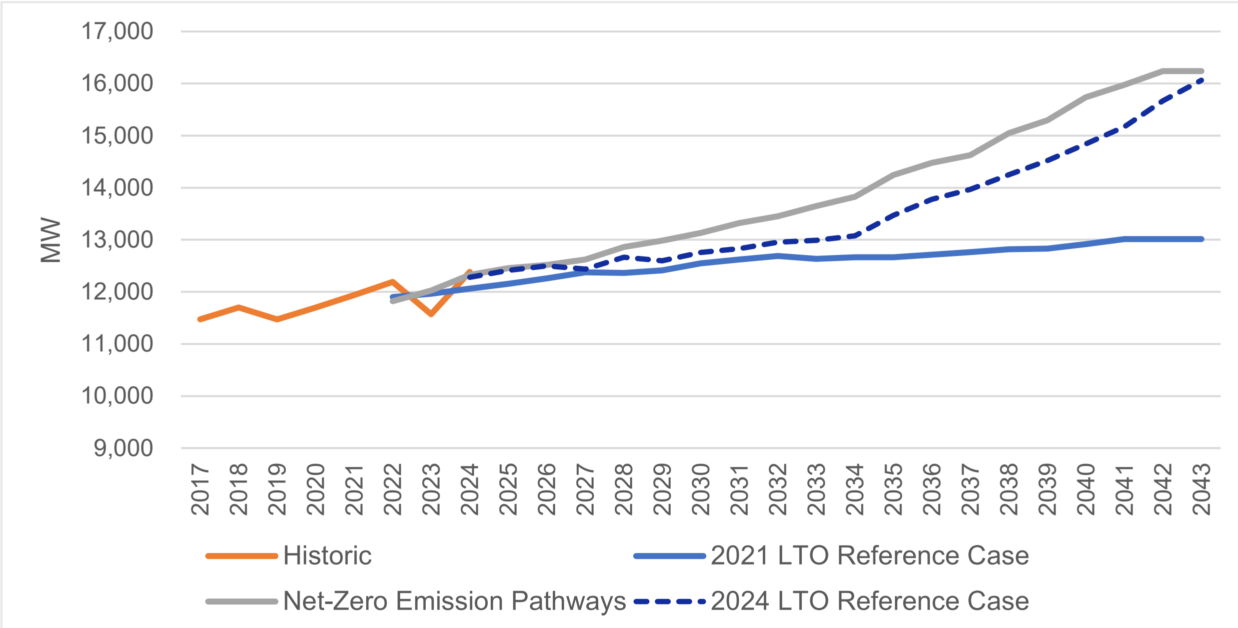


As displayed in Figure 3, forecasted peak AIL will be 31 per cent higher in 2043 than in 2024. This increase in peak load forecasted is stronger than the 12 per cent increase predicted in the 2021 LTO. The strong growth in peak load also surpasses energy growth, which indicates a slight shift from primarily base loads to more variable loads with daily fluctuations. Since EV charging and building heating and cooling load are driving load growth and require more electricity during the winter, Alberta is expected to remain a winter-peaking jurisdiction over the forecast period. The gap between winter and summer peaks is anticipated to widen as EV adoption and electrification of building heating accelerate later in the forecast period. Finally, the increasing penetration of solar DER plays a key role in mitigating peak load during the summer season.

The 2024 LTO assumes managed EV charging profiles in the Reference Case and High Electrification scenario which aids in mitigating peak loads. In these managed EV charging profiles, charging behavior is shifted from on-peak hours, especially late in the afternoon following working hours for many EV owners, to off-peak hours from midnight to early morning when wind generation is strong. While there are currently no specific policies to manage EV charging, certain distribution facility owners (DFOs), including Enmax and ATCO, are running EV charging pilot programs which will provide insights on the potential advantages of managing EV charging behaviours. As the adoption of EVs gains momentum, implementing robust EV charging policies will become essential to avoid the challenges presented by unmitigated demand peaks on Alberta's electricity grid.[8]

[8] For more information about the EV charging load forecast used in the 2024 LTO, see the Load Forecast Methodology section.

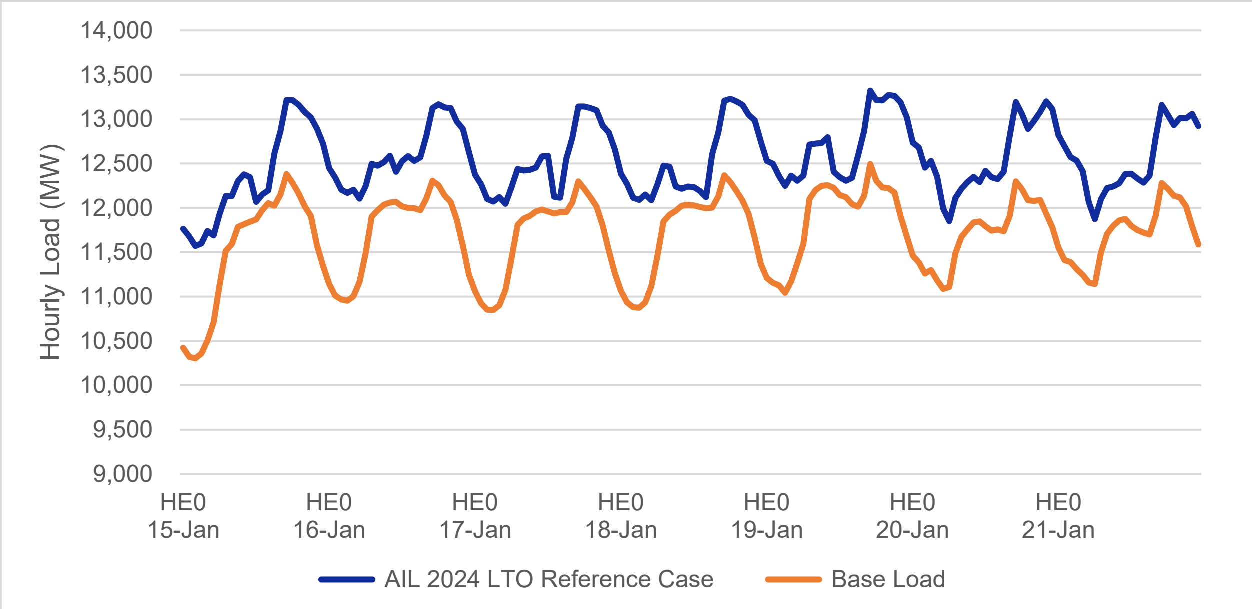
Figure 3: Reference Case – Peak AIL Forecast



Figures 4 and 5 demonstrate how the variable loads discussed above, such as EV charging, building heating and cooling, and DERs result in deviation between baseload, and overall load. Figure 4 reflects forecasted hourly load in the winter of 2035, as such, load from building heating is relatively constant due to the cold weather during the season. The most notable contributor to intraday load variability is EV charging as it follows a consistent pattern, ramping up later in the evening to the early morning hours before dropping off in the morning hours. Further exacerbating this load variation is the DER offset, mainly driven by rooftop solar which reduces load, especially during the afternoon hours, which lead up to the sharp rise in EV charging.

During the summer of 2035 reflected in Figure 5, there are longer hours of DER offset, which overlap with the steep ramp up of EV charging later in the day. Alternatively, EV charging winds down earlier in the morning hours while solar DER generation accelerates, exacerbating the ramp down in load observed in the morning into the afternoon. These daily patterns caused by variable loads are anticipated to cause more frequent and steeper ramps up and down of load in the future.

Figure 4: Reference Case – Winter Peak Week (January 2035): Sensitivity of AIL Peak to Key Load Modifiers



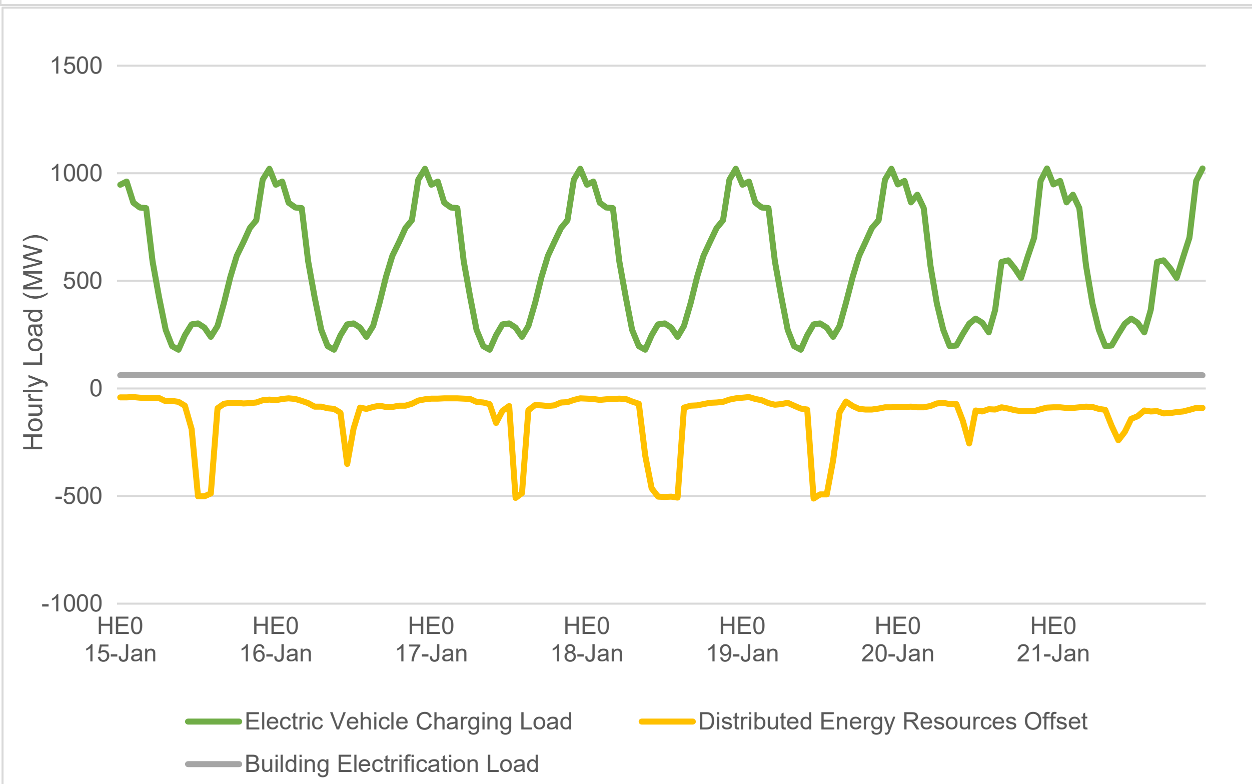
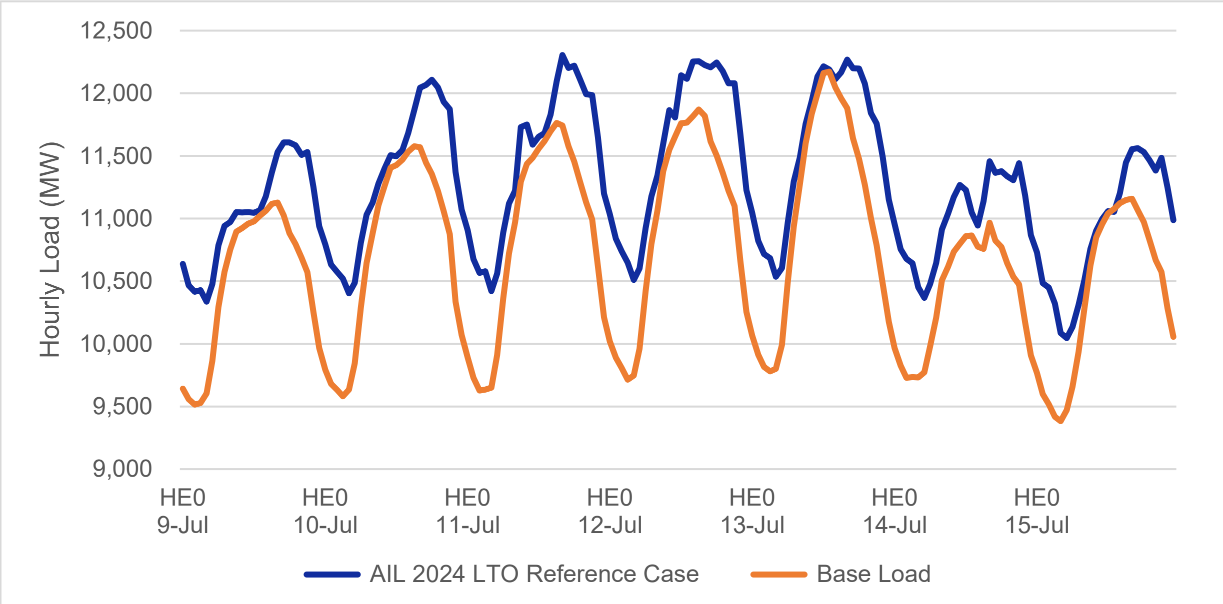
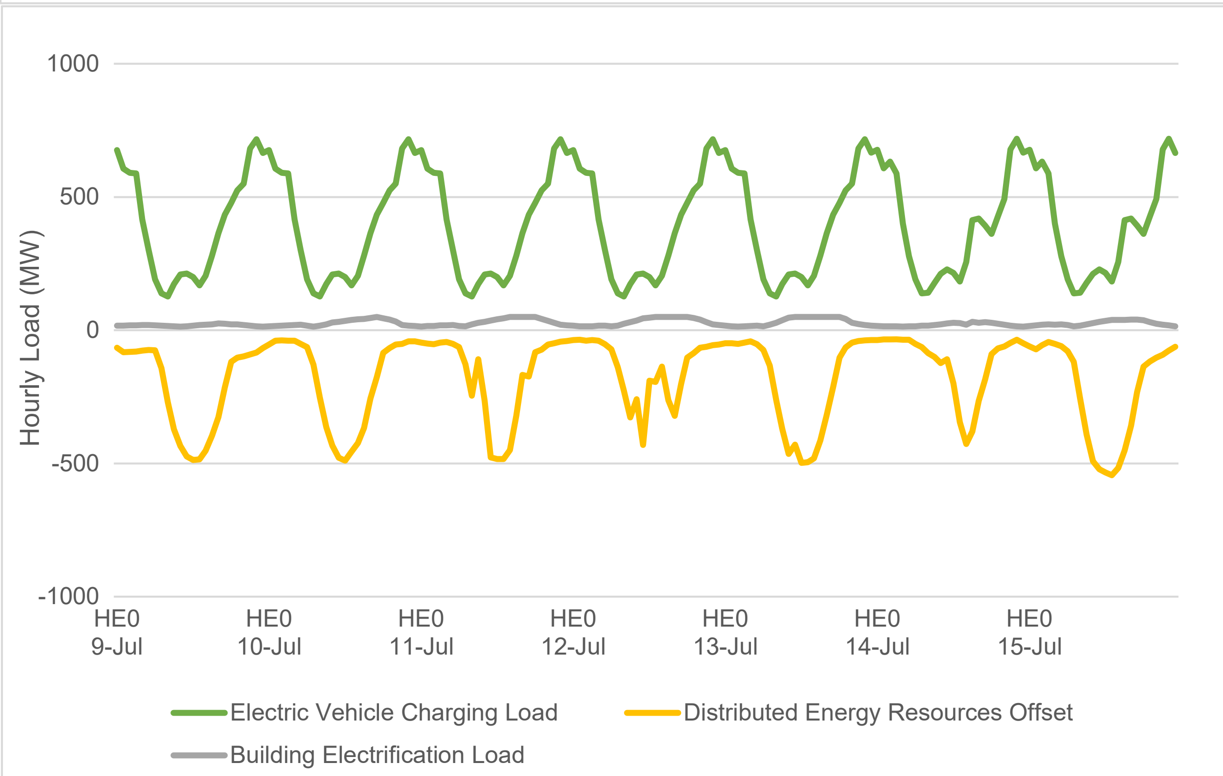


Figure 5: Reference Case – Summer Peak Week (July 2035): Sensitivity of AIL Peak to Key Load Modifiers





Overall, while macroeconomic and oil sands variables drive load growth in the short-term, emerging load additives including EV charging, electrification of building heating and cooling and hydrogen production load drive long-term load growth. These load additives play a key role in the energy transition that is facilitated in part by government policies such as the federal Emissions Reduction Plan that shapes EV new sales mandates and features the Canada Green Buildings Strategy.[9] The 2024 LTO accounts for offsets to load growth including energy efficiency improvements and increased adoption of DERs, mainly rooftop solar. Going into the future, variable load components such as EV charging, building heating and cooling load and rooftop solar will have a significant role in changing the daily load profiles. These changes in daily load profiles include rising peak loads, and steeper ramps up and down throughout the day. Finally, since EV charging and building heating load are higher during the winter season, Alberta is forecasted to remain a winter peaking jurisdiction.

Generation Outlook

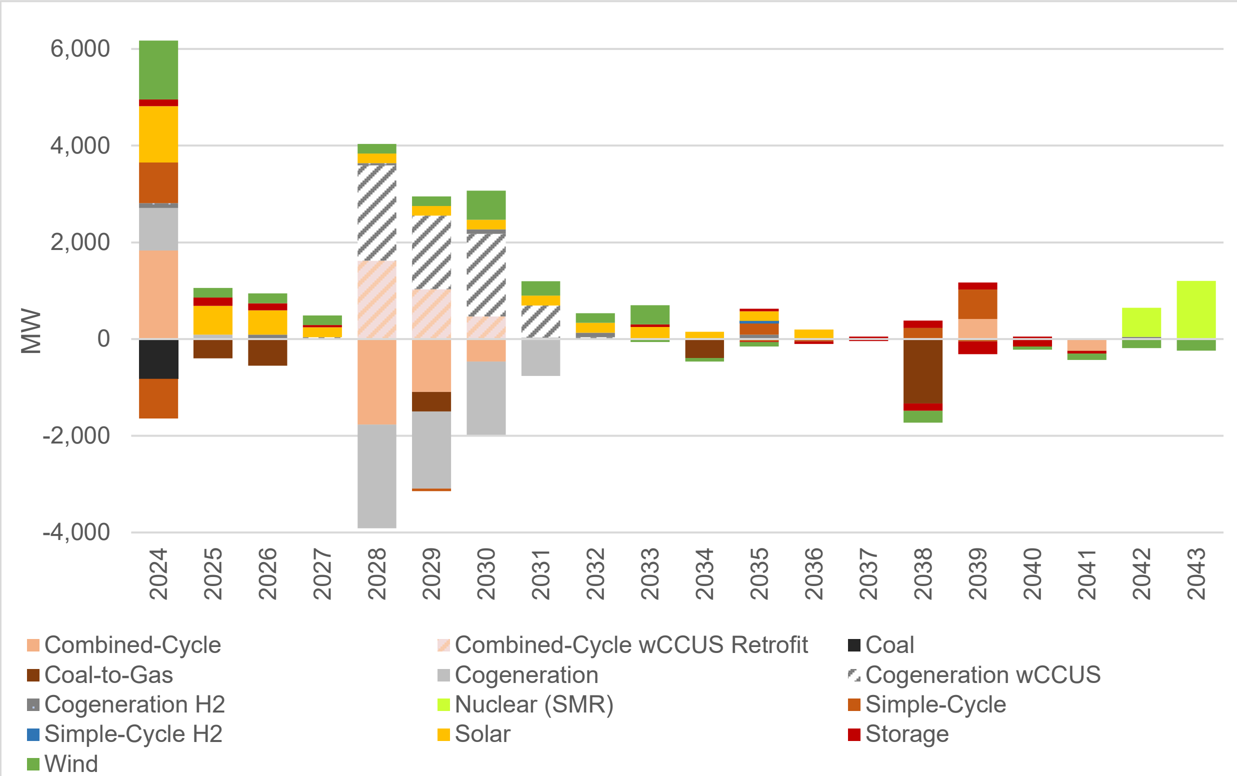
The Reference Case results in 26,626 MW of capacity additions and retrofits between 2024 and 2043. For the purposes of the 2024 LTO, retrofits are counted as a retirement of an existing facility and an addition of a retrofitted facility. Importantly, the capacity additions may not match the capacity retirements, as CCUS decreases the output of the facility.[10] Most of these additions and retrofits are cogeneration with CCUS (5,944 MW), solar (4,260 MW), wind (3,718 MW), and combined-cycle with CCUS (3,121 MW). The majority of additions occur between 2024 and 2030, including all combined-cycle CCUS retrofits and the majority of cogeneration retrofits, coinciding with investment tax credits (ITCs) available until 2031.[11] In this scenario, 1,013 MW and 559 MW of battery energy storage and hydrogen-fired cogeneration, respectively, are incrementally added throughout the timeframe. From 2035 onward, 1,121 MW of simple-cycle, 50 MW of which is hydrogen-fired, is added, correlating to the retirement of the coal-to-gas assets. These simple-cycle units support firming of wind and solar with high flexibility to meet demand.

[9] For more information on regulations influencing the 2024 LTO load forecast, see the Policy and Regulatory Drivers section.

[10] For more information about CCUS additions and retrofits in the 2024 LTO, see the Emerging Technology Drivers section.

[11] For more information on investment tax credits in the 2024 LTO, see the Policy and Regulatory Drivers section.

Figure 6: Reference Case – Capacity Additions and Retirements

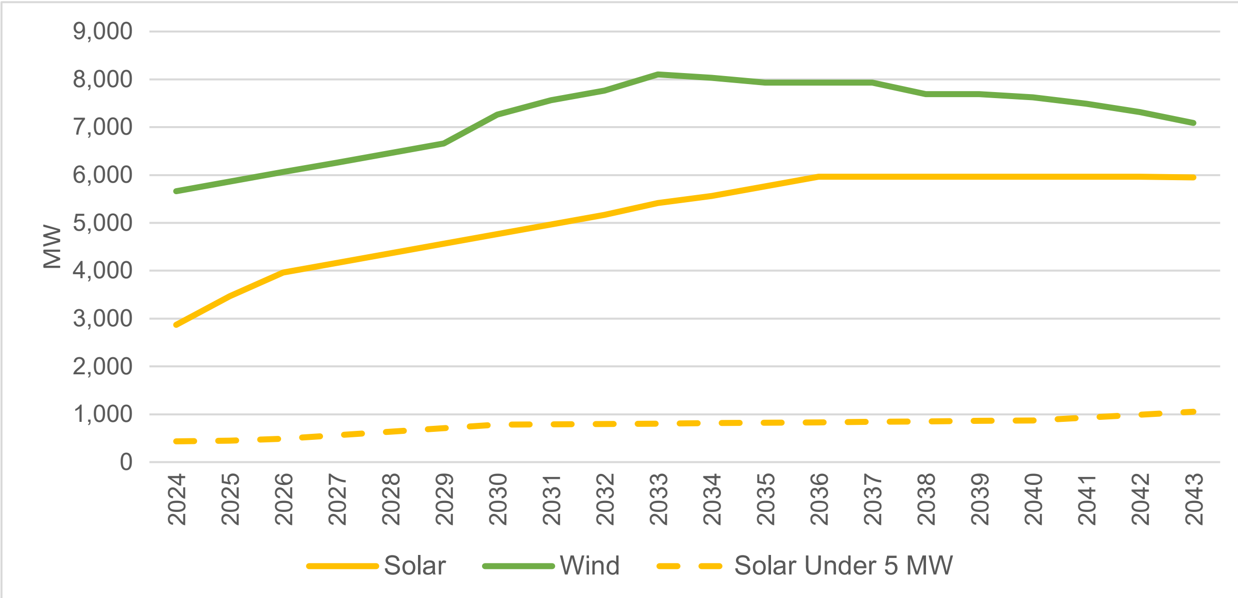


Late in the forecast, nuclear small modular reactors (SMRs) become an economic choice to build, with the first units coming online in 2042. In the Reference Case, nuclear SMRs become the preferred choice for baseload generation given their assumed cost declines and avoidance of any payments for carbon emissions compared to other flexible generation fuel sources like natural gas. As nuclear SMRs are added to the supply mix, they displace existing baseload capacity due to their lower variable costs, while also accounting for firm new load growth.

A significant build of renewables was exogenously added based on the AESO's analysis on corporate demand for power purchase agreements.[12] As well, 700 MW of wind generation is built between 2030 and 2033 as additions that can operate economically within a merchant structure (i.e., non-contracted projects). These additions result in approximately 5,700 MW and 8,000 MW of installed solar and wind capacity, respectively, by 2035. This does not include distributed connected solar facilities under five MW (e.g., solar on households or commercial buildings) which are forecast to contribute an additional 800 MW by 2035 and 1,000 MW by the end of the forecast period. Starting in 2033, existing wind capacity begins to retire based on their assumed end of life. By the end of the forecast timeline, 1,070 MW of wind capacity is expected to retire. No new wind generation is added after 2033, neither to replace retirements nor to add new capacity, indicating that pure merchant facilities may not provide enough of an economic incentive given low expected capture prices due to high renewables penetration and reduced opportunity to generate emissions offsets or Emission Performance Credits (EPCs) under assumed TIER benchmarks.

[12] For more information on the renewables methodology in the 2024 LTO, see the Generation Methodology section.

Figure 7: Reference Case – Installed Renewable Capacity by Year

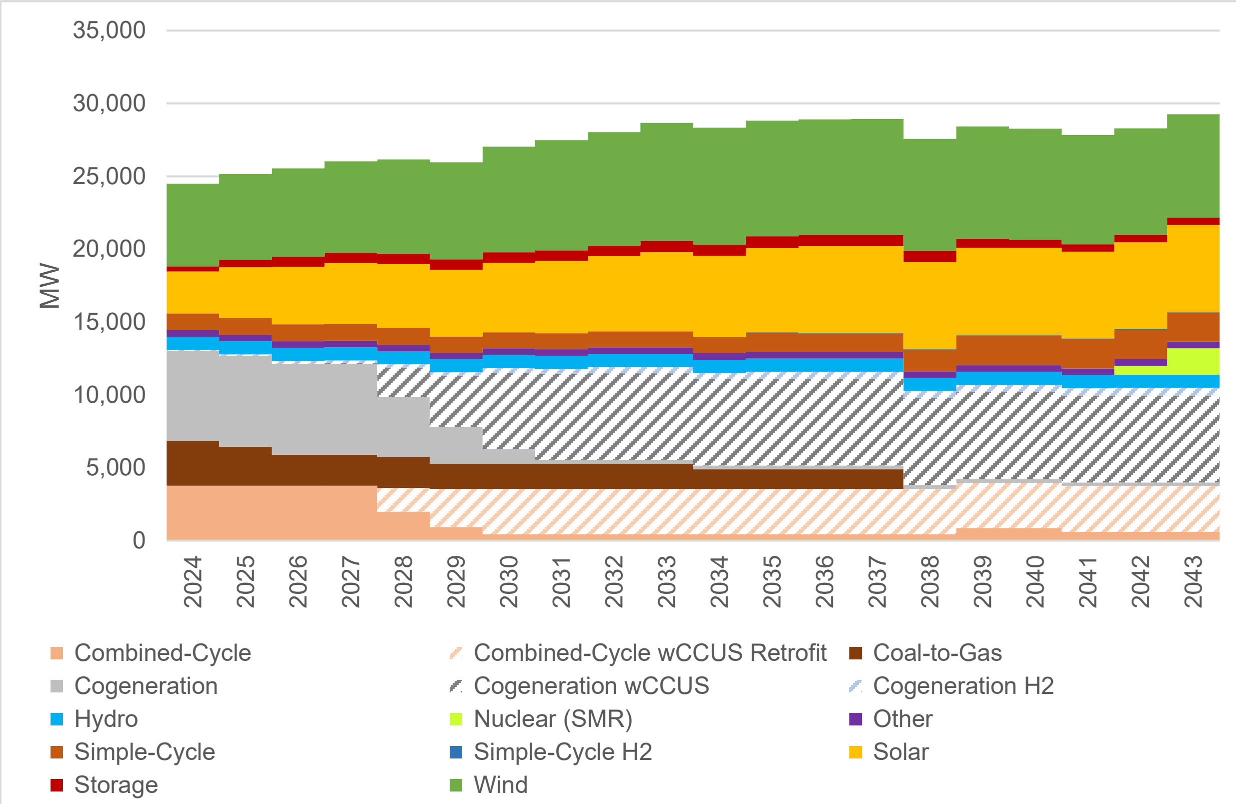


Considering the current supply under construction, the addition of new, large combined-cycle and cogeneration facilities has dampened the economic incentive to invest in further natural gas capacity in the immediate future. These newly integrated generators will bolster baseload generation capabilities, boasting superior efficiency and cost-effectiveness in heat rates compared to the existing generation fleet. Consequently, three of the older, less efficient coal-to-gas units are projected to retire between 2024 and 2026. The remaining coal-to-gas units are anticipated to phase out gradually, with their estimated end of life occurring by the end of 2037. The Reference Case forecasts a notable market shift between 2027 and 2030, marked by the commencement of large-combined cycle and select cogeneration assets retrofitting with CCUS. In the Reference Case, all eligible combined-cycle facilities undergo retrofitting with CCUS technologies, underscoring their economic viability.

Capacity retirements in the Reference Case occur predominantly between 2024 and 2030, coinciding with most of the cogeneration and combined-cycle CCUS retrofits. Coal-to-gas units are forecast to mothball or retire incrementally between 2025 and 2034, with the remaining units retiring in 2038. In the mid-to-late term, some storage, wind, and combined-cycle units retire as they reach end of life.

Wind, solar, and combined-cycle and cogeneration with CCUS comprise most of the generation capacity in the Reference Case. Wind and solar are expected to account for approximately 40 per cent of total capacity by 2027 and reach approximately 50 per cent of total capacity by 2038. At the end of the forecast timeline, wind and solar are expected to account for 45 per cent of total capacity. As noted above, this occurs when some wind facilities begin to reach their end of life and are not replaced by new additions. Instead, nuclear SMR units are built, becoming the preferred choice for non-emitting generation.

Figure 8: Reference Case – Total Capacity

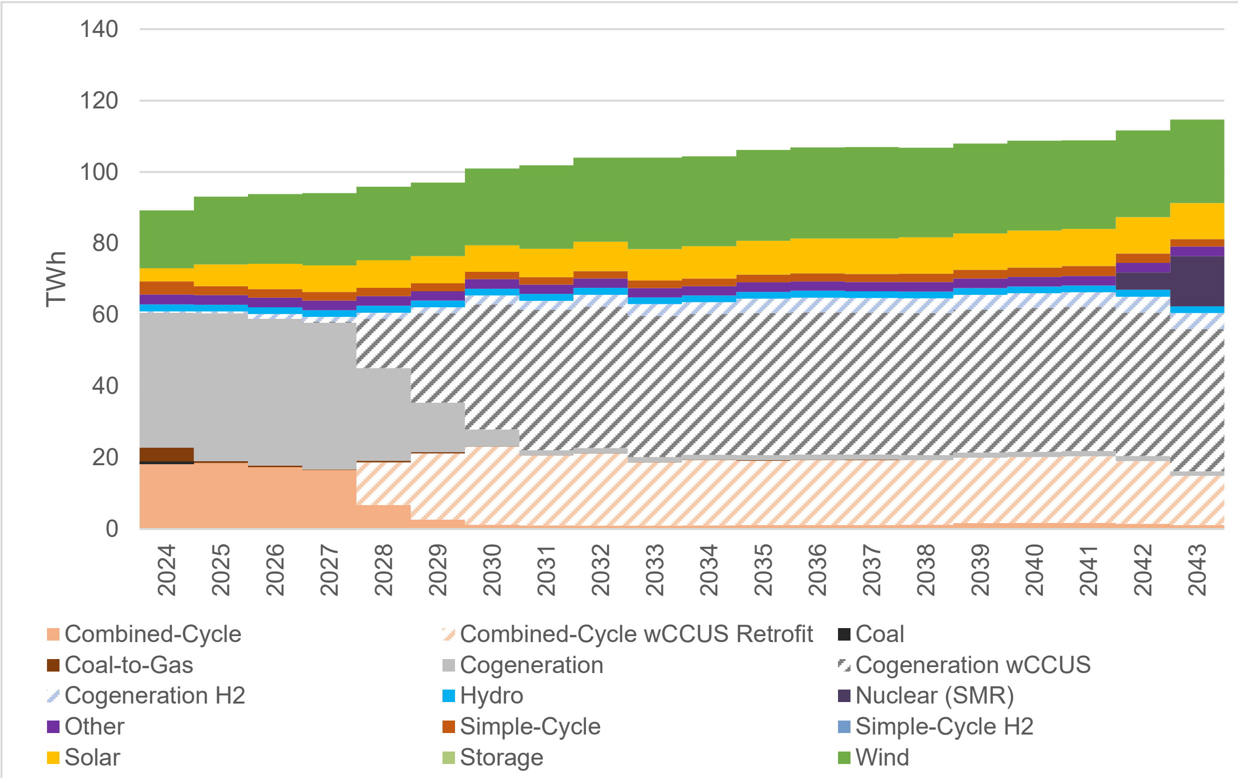


Total Energy Production and Sources

Combined-cycle and cogeneration technologies either with or without CCUS comprise most of the generation in the Reference Case. Natural gas-fired generation continues to supply the majority of Alberta's electricity needs, averaging 60 to 70 per cent of the overall energy throughout the scenario horizon, only declining with the addition of nuclear SMRs. By 2031 and through the forecast horizon, over 90 per cent of natural gas-fired generation is abated.

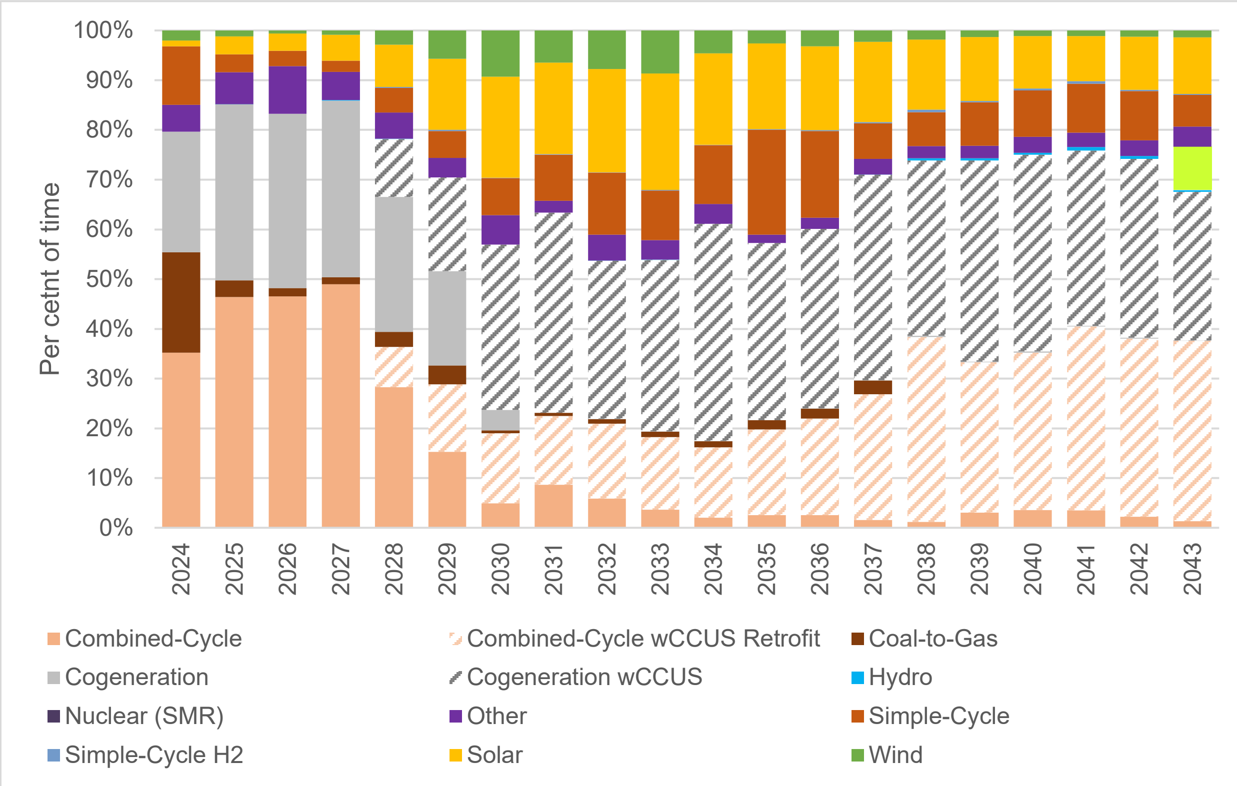
Wind and solar account for approximately 30 per cent of generation throughout the forecast timeline, reaching a maximum of 33 per cent from 2033 to 2040. Generation from renewable energy sources, which includes wind, solar, hydro, geothermal and some biomass, is forecast to account for approximately 30 per cent of total generation by 2025, increasing to approximately 35 per cent by 2033. This would exceed interim and legislated targets established by the *Renewable Electricity Act*, achieving at least 30 per cent of electric energy produced by renewable energy sources five years ahead of the 2030 target.

Figure 9: Reference Case – Alberta Annual Energy



With the high penetration of wind and solar, price volatility is expected to increase. By 2030, the Reference Case forecasts wind and solar to be the marginal technology in approximately 30 per cent of hours, decreasing to approximately 20 per cent of hours in 2035 and 10 per cent of hours in 2040. Beginning in 2035 and through the forecast horizon, cogeneration with CCUS is the marginal technology in 30 to 40 per cent of the time. Similarly, combined-cycle with is the marginal technology in approximately 15 per cent of hours from 2030 to 2035, increasing to roughly 30 to 35 percent of the time by 2038.

Figure 10: Reference Case - Marginal Technology by Year

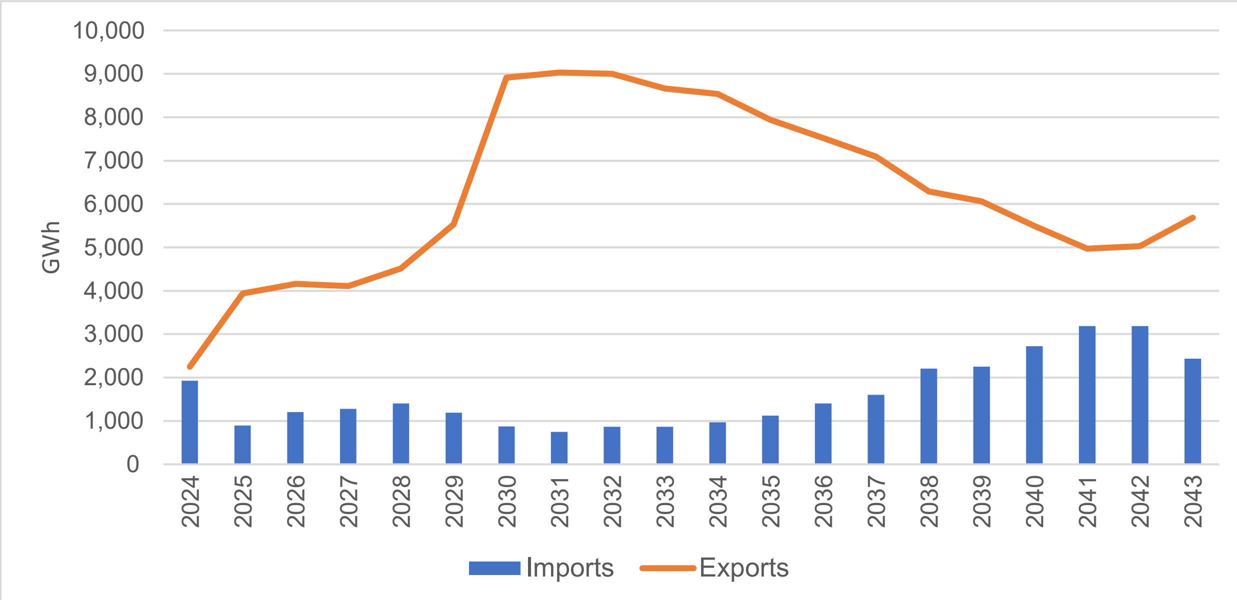


Intertie Utilization

Interties are a key component to the Alberta Interconnected Electric System (AIES), allowing for grid support services and the opportunity to resource share with neighboring jurisdictions. Alberta has traditionally been a net importer of energy across its tie lines, but with the generation expected to come online within the next year, and increased penetration of low-cost wind and solar, Alberta is expected to become a net exporter. Intertie flows generally have a tightening effect on electricity prices, such that high-priced hours encourage more imports, depressing price. The opposite is true for low-priced hours when there is high renewable generation.

In the Reference Case, Alberta reaches maximum net exports in the 2030 to 2034 timeframe, as installed renewables capacity peaks and both new and retrofit CCUS natural gas-fired baseload generation saturates the market for energy. During this time, annual average net exports reach almost 8,000 GWh. After this, a combination of unit retirements, including certain renewable facilities and the remainder of the coal-to-gas units, limited baseload generation capacity additions and increasing demand toward the end of the forecast horizon, cause a pullback in exports and an increasing reliance on imports until 2042. At the tail end of the forecast horizon, 1,800 MW of new nuclear SMR baseload additions begin to swing the intertie dynamics in favour of exports.

Figure 11: Reference Case - Intertie Utilization



Results Summary

In the Reference Case, wind, solar and combined-cycle and cogeneration with CCUS are expected to provide the majority of electricity generation. Late in the forecast, nuclear SMRs are built as baseload generation. Wind and solar are expected to account for approximately one-third of total generation throughout the forecast and reach 50 per cent of installed capacity by 2038. Natural gas-fired generation is expected to remain an important source of electricity, providing the majority of energy throughout the forecast and only declining with the addition of nuclear SMRs. By 2031, over 90 per cent of natural gas-fired generation is abated. Emerging technologies like CCUS and nuclear SMRs are driven by a combination of ITCs, increasing regulatory stringency, and next-of-a-kind cost declines, highlighting the influence of government policy and technological development timelines on the forecast supply mix. Alberta is expected to be a net-exporter throughout the forecast, particularly between 2030 and 2034 when installed renewable capacity peaks. Increased imports and decreased exports are used to support demand in the period between the final coal-to-gas retirements in 2038 and the first nuclear SMR additions in 2041.

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