



AESO Net-Zero Emissions Pathways Report

Table of contents

EXECUTIVE SUMMARY	1
AESO's Role in a Net-Zero Transition and Purpose of this Report	2
Policy Context and Key Assumptions	3
Scenarios, Sensitivities, Signposts and Challenges	4
Key Conclusions	6
NET-ZERO EMISSIONS SCENARIOS	8
Dispatchable Dominant Scenario	8
First-Mover Advantage Scenario	10
Renewables and Storage Rush Scenario	11
Option Value of Converted Coal-to-Gas Units and Other Unabated Thermal Units	12
Alternatives Challenged to be Achievable by 2035	12
Hydroelectric	12
Nuclear or Small Modular Reactors	13
Transmission Interconnections	13
ELECTRIFICATION PATHWAYS	14
Enhancements in Load Forecast Methodology	14
Existing Load Categories	15
Distributed Energy Resources (DERs)	16
Transportation	16
Buildings	19
New Industrial Activities	21
Load Forecast	22
Load Sensitivities and Electrification Signposts	27
Demand Transmission Service Load	28
SUPPLY DECARBONIZATION PATHWAYS	30
Enhancements in Emissions and Generation Forecast Methodologies	30
Emissions Policy Modelling	30
Additional Generation Types for Net-Zero Analysis	32
Additional Energy Storage Technologies for Net-Zero Analysis	32
Characteristics of Net-Zero Generation Technologies	33
Generation Forecasts	38
Dispatchable Dominant Scenario	38
First-Mover Advantage Scenario	42

Renewables and Storage Rush Scenario	45
Total Capacity	46
Total Generation	47
EMISSIONS REDUCTION OUTCOMES	49
Emissions Calculation Methodology	49
Additional Opportunities for Emission Reductions	50
Offsets and Credits Enabling Net-Zero	51
Emissions Results	51
Dispatchable Dominant Scenario Emissions Results	52
First-Mover Advantage Scenario Emissions Results	52
Renewables and Storage Rush Scenario Emissions Results	53
RESOURCE ADEQUACY OUTCOMES	54
Resource Adequacy Sensitivities	54
Base Case	54
Demand Response (DR)	54
Demand Management (DM)	55
Removal of Unabated Gas (UNG)	55
Removal of Storage (Storage)	55
Resource Adequacy Results	55
Dispatchable Dominant	55
First-Mover Advantage	57
Renewables and Storage Rush	59
Additional Potential Reliability Challenges in a Net-Zero Emissions Power System	61
COST OUTCOMES	63
Generation Costs (Capital and Operating)	63
Levelized Costs of included Generation and Storage	64
Transmission Costs	65
Cost Estimates	65
Dispatchable Dominant Scenario	66
First-Mover Advantage Scenario	67
Renewables and Storage Rush Scenario	68
CONCLUSION	72
Emissions Reductions	72
Resource Adequacy	72
Costs	73
Next Steps	74

Executive Summary



The AESO is responsible for the reliability of Alberta's power system and we are acutely aware that moving our predominately fossil fuel-based grid to net-zero must be done thoughtfully and in a way that ensures reliability and minimizes cost to Albertans.

A growing commitment to electrification and decarbonization continues to drive government policy decisions and legislation. At the United Nations Climate Change Conference in Glasgow in 2021 (COP26), many countries, including Canada, pledged to reach net-zero emissions by 2050.¹ Policymakers across all levels of government in Canada, along with many corporate organizations, have also announced decarbonization dates and objectives.

The electricity sector is viewed as critical in achieving economy-wide decarbonization goals for two reasons. First, many low and zero-emitting generation technologies are already commercially available and could potentially be expanded to replace the current thermal generation fleet. When viewed at a national level, Canada's electricity system is already largely carbon-emissions free, although significant regional differences remain. Second, a net-zero grid would facilitate other economic sectors that do not have low-emitting alternatives to electrify, providing a mechanism to reach their decarbonization objectives. Since a faster transition in the electricity sector is viewed as more achievable, and to ensure emissions continue to decline as other sectors of the economy electrify, most policy discussions focus on achieving a net-zero electricity system by 2035.

“The dual forces of increased electrification and supply decarbonization are central to the AESO’s Net-Zero Emissions Pathways report (AESO Net-Zero Report).”



This analysis reviews potential supply and demand combinations that may enable Alberta to reach a net-zero electricity system by 2035 while also considering potential implications to electric system reliability, the wholesale electricity market and supply and transmission costs. Various technologies may provide methods of decarbonizing electricity supply while increased electricity demand may enable emissions reductions in other areas including transportation, heating, and industrial activities. These shifts are expected to have a major impact on future electricity supply-and-demand patterns.

¹ For a summary of the Government of Canada's commitment at COP26, see: <https://www.canada.ca/en/services/environment/weather/climatechange/canada-international-action/un-climate-change-conference/cop26-summit/achievements-at-cop26.html>

A move towards a net-zero emissions electricity system will require significant capital investments in the sector including the areas of supply, delivery and the efficiency and management of demand. In Alberta's deregulated industry structure, these significant investments will be required from a range of entities. Transmission system investments will be made by cost-of-service regulated entities based on AESO planning and Alberta Utilities Commission (AUC) approval processes. The bulk of investments and costs for constructing and operating new supply will be required from non-regulated risk-taking entities. Understanding the potential opportunities, challenges and costs of a transformation to a net-zero electric system is therefore critical for both consumers and investors, in addition to policymakers. The broader transition to a net-zero society will also involve many cost and benefit puts and takes across the economy which are beyond the scope of this report.



“For the AESO, analyzing these potential pathways for Alberta’s electricity sector is the first step in understanding operational, market and cost implications associated with a future of increased electrification and low-emissions supply.”

As part of the development of this report and analysis, the AESO undertook a robust stakeholder engagement process. Two opportunities to provide detailed written feedback and a stakeholder session were held prior to the completion of the report with one final stakeholder information session held following the publication of the report. Stakeholder knowledge of future trends, development costs, technological expertise, and perspectives on decarbonization pathways helped to shape the AESO's Net-Zero Report and develop more robust net-zero pathway assessments. The AESO considered all feedback received from stakeholders through the development of this report and looks forward to additional input as Alberta's electric system continues to transform.

AESO's Role in a Net-Zero Transition and Purpose of this Report

A critical responsibility of the AESO is to ensure that Albertans benefit from a safe, reliable, and economic electricity system under a variety of future outcomes. A well-functioning power grid is fundamental to Alberta's economic prosperity. The AESO is committed to providing policy makers and stakeholders with timely analysis and insights regarding the implications of a transforming electric system. As a not-for-profit entity with a public interest mandate and no commercial ownership within the industry, the AESO's analysis is objective and considers impacts on a wide range of stakeholders. This AESO analysis is therefore intended to enable all stakeholders to make informed decisions.

The AESO Net-Zero Report is not intended to represent a specific policy or technology recommendation, nor does it reflect knowledge or detailed analysis of a particular government policy implementation. By examining a range of potential outcomes, the report will enable the AESO and stakeholders to better understand potential trade-offs and risks involved in transitioning to a net-zero grid. The insights gained through this report will allow the AESO and stakeholders to identify and prioritize additional focus and work required in areas such as policy development, industry coordination, grid planning, market evolution and grid reliability operations. And because development, decision-making, approval and implementation timelines in each of these areas can be lengthy, it is important to start the conversation on the transformation now with the understanding that it will be an iterative process.

Policy Context and Key Assumptions

For the purposes of this report, net-zero greenhouse gas emissions are defined as the combination of zero- or low-emissions technologies that may be paired with the use of offsets and credits that lead to a calculated emissions outcome equivalent to zero greenhouse gas emissions. In preparing this report, the AESO assumed the following about the policies that are implemented to decarbonize Alberta's electricity supply by 2035 and increase electrification in other economic sectors to achieve net-zero:

- The federal government will continue to increase the carbon tax at a rate of \$15/year, in pursuit of a \$170-per-tonne carbon price by 2030.² A more modest inflationary two per cent annual increase in the price of carbon is applied thereafter.
- Continued provincial equivalency with federal carbon pricing and legislation in Alberta. Specifically, the Technology Innovation and Emissions Reduction (TIER) Regulation³ will continue to apply to large emitters in Alberta. However, the “high-performance benchmarks” for electricity and hydrogen production within the TIER Regulation are assumed to decline annually, in a uniform manner, reaching zero by 2035 for electricity and zero by 2050 for hydrogen. The declines in the “high-performance benchmarks” would reflect increased exposure to carbon prices for greenhouse gas emitters.
- For the transportation and buildings sector, the details announced in the federal 2030 Emissions Reduction Plan (ERP) will be achieved.⁴
- For the potential demand growth related to hydrogen production in Alberta, the AESO relied on near-term announced capital projects, as well as long-term hydrogen production projections from the Canada Energy Regulator.⁵ The emerging hydrogen production technologies used in the AESO's model are aligned with the Government of Alberta's Hydrogen Roadmap.⁶
- For other economic sectors for which decarbonization and electrification goals lack details (i.e., policy targets, dates or timelines, technological readiness) at the time of modelling, sensitivities were run by adopting reasonable assumptions on what decarbonization and electrification may look like for those sectors (details are in the section Load Sensitivities and Signposts).
- The AESO has also made the general assumption that the regulatory and policy environment supports the timely approval, construction and efficient operation of infrastructure required to enable the net-zero transition. This includes electricity transmission as well as carbon capture, transportation and storage and hydrogen production and transportation infrastructure.

Taken together, a policy framework that incorporates the assumptions in this report could incent substantial decarbonization of the electricity sector, as well as increased electrification of other economic sectors, by 2035. These policy assumptions were made entirely for the purpose of the analytical exercise described in the AESO's Net-Zero Report and are in no way intended to reflect investment guidance or policy recommendations by the AESO.

² <https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html>

³ The Technology Innovation and Emissions Reduction Regulation is the carbon legislation that currently applies to large emitters in Alberta.

⁴ The federal 2030 Emissions Reduction Plan (ERP) can be found here: <https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030.html>

⁵ The 2021 Canada Energy Future report and data can be found here: <https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/index.html>

⁶ Alberta's Hydrogen Roadmap can be found here: <https://www.alberta.ca/hydrogen-roadmap.aspx>

As policy and regulation continue to progress, including the federal ERP (which includes the Clean Electricity Standard) and the provincial TIER program, the AESO will assess and determine whether they are adequately reflected in the scenarios described in this report and, if they are not, will account for them in future outlooks.

Scenarios, Sensitivities, Signposts and Challenges

Many pathways may be taken to achieve a net-zero emissions electricity system by 2035. There are also many uncertainties concerning the technologies that may be involved and their specific impacts on supply and demand. Uncertainties on the energy demand (load) side include the rate of penetration of electric vehicles (EVs) and electric heating, and the degree to which new and existing industrial processes are electrified. In terms of energy storage, the level of participation may depend on cost declines and the inclusion of longer-duration technologies. From the energy supply (generation) perspective, given the current state of infancy of abated thermal assets including combined-cycle with carbon capture and storage (CCS), hydrogen-fired units and other low-carbon generation technologies, the rate of cost declines and operationalization of these assets and their respective infrastructure may be different. These moving pieces, along with evolving carbon policies, further compound the uncertainty of the future demand and supply mix within the Alberta Interconnected Electric System (AIES).

To effectively assess the potential implications of a net-zero transformation in the face of this uncertainty, the AESO has employed scenarios as part of its analysis. Scenarios provide value by allowing the examination of a wide range of future outcomes and are widely utilized by the AESO including, for example, in its Long-term Outlook (LTO) process. The AESO's Net-Zero Report builds on the 2021 LTO to examine additional scenarios with greater electrification and higher levels of low-carbon and renewables generation development.



“For the AESO’s Net-Zero Report, three scenarios were developed from a much larger set of potential pathways. The three scenarios utilize the same load forecast and include varying levels of solar, wind, energy storage and abated thermal assets.”

These scenarios were selected as they were assessed to be the most likely to be implementable by 2035 and within the current market structure, while still providing sufficient variety to enable an analysis of a wide range of potential operational, market and cost outcomes. Through scenario assessment on the supply side, the AESO can test future reliability, market, and cost implications of transitioning to a net-zero carbon emissions electricity sector. The AESO has also completed sensitivities on load to further test the range of outcomes and better understand key signposts to monitor.

The scenarios examined by the AESO are:

- **Dispatchable Dominant:** A scenario where thermal units with low carbon emissions, resulting from carbon capture or hydrogen combustion technologies, continue to form a significant portion of Alberta’s supply mix.
- **First-Mover Advantage:** A scenario with continued high growth in renewables and moderate energy storage additions which displace dispatchable thermal units.
- **Renewables and Storage Rush:** The highest renewables-addition scenario coupled with high volumes of energy storage and the lowest amount of low carbon thermal-based supply additions.

Within these scenarios, the AESO assumes that the electricity market structure remains as it is today. All of the scenarios assume substantial continued supply provided by cogeneration units at industrial sites and that the emissions from these facilities, and any mitigation requirements for these emissions, are associated with the respective host industries. The AESO did not include any additional interties, hydro generation or small modular reactors (SMRs) within the scenarios, as their long development cycle would be expected to extend beyond the 2035 target timeframe. In addition, high capital costs and, for interties, increased seams between regulated and competitive markets make these options more challenging to incorporate into Alberta's market construct.

“All three scenarios face significant implementation challenges, not the least of which is the fact that the 2035 target date is only 13 years away.”



The timeline appears ambitious when viewed in the context of additional considerations, such as ongoing regulatory uncertainty and regulatory process decision timelines, the lead-time and global supply chain requirements for such a large turnover of capital stock (load and generation), and the imperative to have a robust electric transmission and distribution system in place. In addition, a net-zero transformation of Alberta's electric system is likely to depend on the timely development of significant infrastructure outside the electric system in areas such as carbon capture or hydrogen production and transportation. Cost is also a risk in the outlook when considering the development of many large-scale, overlapping projects. In the past, Alberta experienced significant increases in labour and material costs when multiple oil sands projects were developed simultaneously alongside a supercritical coal project.

To allow for assessment of which of the three scenarios is likely to emerge over time, and to modify, add or discard scenarios for future analysis, the AESO has created signposts for periodic review. Signposts to monitor include:

- Future regulatory activities, which may hinder or accelerate investment decisions on capital-intensive projects. This will include activities at the federal level (i.e., development of the Clean Electricity Standard, carbon pricing, and tax treatment of emerging technologies) and at the provincial level (i.e., an equivalency agreement with the federal government through TIER).
- Technology improvements, costs and required infrastructure, which may change the rate of penetration for EVs and heating load.
- Shifts in costs for abated thermal assets.
- Shifts in costs for renewables and energy storage.
- Lead time for abated thermal generation (i.e., CCS or hydrogen), which may shift in response to the commercialization of technology and development of required infrastructure (e.g., hydrogen production and transportation and carbon capture, transportation and storage).
- Regulatory and investment-community pressures in other economic sectors, notably those that are harder to abate and likely to electrify (e.g., oil and gas, heavy industry), which may impact Alberta's load and/or supply mix in multiple ways.

Key Conclusions

The AESO Net-Zero Report has reached the following conclusions:

- The multiple potential pathways to achieve net-zero, of which the AESO has studied three, are highly uncertain and present a significant risk to achieving the end goal by 2035. Meeting the less-than-13-year timeline is ambitious considering policy/regulation uncertainty, layered regulatory approvals required for projects, technology commercialization timing and cost curves, supply chain challenges, and the long development timelines for all types of energy-related infrastructure.
- Relative to a non-net-zero future, transitioning will require an additional \$44 to \$52 billion in generation capital investments (including a return on investment), generation operating costs and in transmission system revenue requirements from 2022–2041. This represents a 30 per cent to 36 per cent increase relative to the baseline of the 2021 LTO Reference Case.
 - Of this, generation capital investments (return of and on capital) are \$27 to \$37 billion or 59 per cent to 71 per cent
 - Generating operating costs are \$11 to \$19 billion or 20 per cent to 41 per cent
 - Transmission revenue requirements are \$0.3 to \$4.3 billion or less than 10 per cent
 - The cost composition differs between the net-zero scenarios but the total costs between scenarios are within five per cent of each other
 - The First-Mover Advantage Scenario has the lowest costs while the Renewables and Storage Rush Scenario has the highest costs
 - Normalized across system load, costs may be \$50/MWh or 40 per cent higher by 2035
 - The costs estimated by the AESO represent a subset of electric system costs. Additional work and industry discussions will be required to better understand potential distribution system and integration costs
 - A net-zero transition will involve puts and takes across the economy and consumers may face higher costs in some areas offset by lower costs in others. The AESO's analysis is limited to a subset of the electricity system and is not an economy-wide assessment.
- Alberta's market structure is capable of delivering sufficient supply to meet demand during the net-zero transformation with the following considerations:
 - Risks are dependent on the timing of generation entry and exit
 - Risk is unacceptable in all scenarios if legacy unabated gas units exit the market and are not replaced by supply with similar operating characteristics
 - Increased demand response and flexibility can significantly decrease risk
 - Sufficient energy storage is critical to supply adequacy in a high-renewables case
 - Other aspects of reliability such as ramping capability, inertia, frequency response and system fault response are likely to be negatively impacted by a net-zero transformation, but further study to fully assess impacts and mitigation is required

- The application of offsets will be required to achieve a net-zero electricity system by 2035
 - All net-zero pathways scenarios modelled result in residual physical emissions
 - Abating all electric system physical emissions to zero would come with rapidly increasing costs and is operationally unrealistic
 - The majority of cogeneration emissions are associated with industries outside the electric sector and are not included in the AESO's analysis. Widespread application of CCS to these cogeneration assets would increase Alberta's electricity demand by five per cent
- Demand growth under a net-zero transition, even considering increased electrification, is expected to be lower than historically observed rates, which the Alberta market has accommodated
 - New components of load from transportation, heating and new industrial production are partially offset by increased rooftop solar
 - Demand will become considerably more variable over time
 - Demand growth rates accelerate post-2035 as electrification takes hold
 - Demand growth remains most sensitive to oil sands production, but EV adoption rates are expected to become a comparable source of uncertainty during the net-zero transformation

The AESO will incorporate the net-zero analysis and future analyses into its market evolution and reliability roadmaps. The AESO will monitor and assess the system for evolving future scenarios and ensure reliability while seeking to minimize cost increases to system users. Such assessments will be ongoing and incorporated into future LTO and Long-term Transmission Plan (LTP) reports, with the AESO keeping stakeholders informed on potential assessments and findings.

Net-Zero Emissions Scenarios



To assess impacts given the uncertainty of future outcomes of the Alberta electricity system, the AESO has undertaken a scenario-based approach that contains varying degrees of renewables generation, thermal generation, and energy storage. The AESO will monitor signposts to ascertain whether we are trending towards a specific scenario, or a drastically different scenario from the ones considered. This approach allows the AESO to determine steps that may need to be taken to ensure system reliability at a reasonable cost for stakeholders. The AESO's Net-Zero Pathways Analysis quantifies three supply-mix scenarios that could lead to substantial physical greenhouse gas emissions reductions. When paired with regulatory mechanisms (i.e., emissions offsets or emissions performance credits) or retrofitting existing thermal assets with low-carbon technologies, these scenarios represent potential net-zero emissions pathways for the electricity sector by 2035. Each scenario presents unique uncertainties and different opportunities and challenges in terms of cost, operation, and risk to the AIES.

A common challenge to each scenario is that the timing to achieve net-zero by 2035 is ambitious. A significant capital stock turnover of thermal, renewables and energy storage assets would be required to achieve the decarbonization of the AIES. In addition to supply-side and energy storage changes, lead-time challenges may result with supporting infrastructure, including transmission development, distribution development and full value-chain infrastructure required for hydrogen and CCS. Consequently, mitigation strategies may require unabated existing thermal generation to operate past 2035 for reliability purposes.

DISPATCHABLE DOMINANT SCENARIO

The Dispatchable Dominant Scenario explores a world where very low or zero-carbon-emissions thermal units form the bulk of supply. The scenario is driven by the capital turnover of most unabated thermal assets into abated assets by the way of carbon capture technologies. The scenario demonstrates potential outcomes associated with the deployment of combined-cycle generation with CCS and blue hydrogen-fired simple-cycle generation. These technologies provide reliable baseload and flexible generation needs that can be dispatched and cycled to meet load regardless of seasonal or intra-day conditions. Consequently, there is limited need for energy storage to balance flexible and intermittent generation within this scenario.

The technologies in this scenario are in the early commercialization stages, which presents cost escalation risks, timing challenges and risk of carbon capture underperformance. Additionally, the scenario relies on the development of integrated carbon capture and hydrogen infrastructure strategies (i.e., storage and transport). A positive indicator is that CCS technologies applied to non-electric generation processes have been successfully implemented in Alberta and many other jurisdictions. Knowledge gained from operational facilities with CCS attached to coal-fired generation can also be applied. In addition, the technologies present a significant opportunity for near-term decarbonization of natural gas-fired infrastructure while providing reliable generation from dispatchable resources.

Recent announcements of investment tax credits⁷ and government support of hydrogen and carbon capture technologies will impact the economics of these facilities and increase the possibility that such technological developments materialize. The structure of the investment tax credits may also incent investors to accelerate their activities to receive the full value of the incentives. Costs of carbon capture and hydrogen technologies may also decline as the technology experiences greater adoption and maturity, potentially leading to increased application in Alberta's generation fleet.

Based on the AESO's long-term market-economic based simulation model, the economic build of combined-cycle with CCS and hydrogen-fired simple-cycle technologies was indicated. These technologies dominated the development landscape as baseload and peaking assets, respectively. Combined-cycle with CCS enters first, replacing retiring coal-to-gas conversions in the 2020s. Hydrogen-fired simple-cycle enters later in the 2030s, taking advantage of continued coal-to-gas retirements and some conventional natural gas-fired simple-cycle and combined-cycle retirements. Hydrogen-fired simple-cycle ramps up in low solar and wind hours and combined-cycle with CCS runs in a baseload profile.

The scenario did not result in the development of hydrogen-fired combined-cycle generation. However, depending on prevailing capital and fuel costs, this technology could be a viable competitor in Alberta's electricity market and displace combined-cycle with CCS or hydrogen-fired simple-cycle developments. Retrofit opportunities for both hydrogen-firing and post-combustion carbon capture may play a role in the economic decarbonization of Alberta's electricity sector. However, the unique nature of individual facility retrofit opportunities and challenges present significant difficulties in forecasting their viability.

Energy storage developments in this scenario are limited to lithium-ion batteries that would be expected to participate primarily in ancillary service markets.

Reasons that this scenario may not prevail include developers allocating scarce capital to renewables given the drive toward corporate power purchase agreements (PPAs) and the ease of developing new, less complex wind and solar technologies. In addition, significant support infrastructure will need to be developed in parallel (i.e., carbon capture and hydrogen hubs and pipelines). If cost assumptions are not achieved and complete CCS strategies are not timely, projects may be delayed or cancelled. The recently announced federal government preferential financial treatment for the development of CCS may mitigate some of these outcomes by providing greater incentives prior to the end of the decade and supporting accelerated development.

⁷ Please find all relevant details regarding investment tax credits here: <https://www.canada.ca/en/department-finance/programs/consultations/2021/investment-tax-credit-carbon-capture-utilization-storage.html>

FIRST-MOVER ADVANTAGE SCENARIO

The First-Mover Advantage Scenario demonstrates the continued deployment of wind and solar intermittent renewables generation resources by 2035. Current trends in corporate sustainability, government support, tax incentives, technological advancement and the associated capital cost reductions have enabled the construction of meaningful amounts of wind and solar generation in Alberta. The First-Mover Advantage Scenario represents a future net-zero outcome that continues the development of significant volumes of wind and solar generation, given the current availability of these technologies with minimal construction timelines. This scenario also relies on combined-cycle generation with CCS and hydrogen-fired simple-cycle generation to supply energy at times when renewables generation may be insufficient or unavailable to meet the growing demands of electrification.

First-Mover Advantage forecasts strong solar development in the 2020s driven by corporate PPA development and declining capital costs. This also means that solar development does not continue into the 2030s, as the correlated nature of solar assets drives the achieved revenue low enough to disincentivize investment. Wind development is forecast to continue into the 2030s due to more diversity in its production profile, higher capacity factors, and stronger resulting revenue. These renewables additions are modelled outside of the AESO's long-term capacity expansion tool based on project economics and corporate PPA growth. The AESO's long-term capacity tool was then used to determine the thermal build, keeping the renewables build constant.

Much like the Dispatchable Dominant scenario, the First-Mover Advantage Scenario only considers lithium-ion energy storage development, which is assumed to primarily participate in ancillary service markets. Reasons that this scenario may not materialize include solar and wind costs failing to decline at the assumed rates and failure to attract corporate PPAs. Lack of development of combined-cycle with CCS and hydrogen-fired technologies due to high construction costs, lack of supporting infrastructure or dissatisfactory operational performance also represent a risk that low-carbon thermal assets may not materialize as depicted in this scenario. Factors supporting the development of combined-cycle with CCS and hydrogen-fired technologies are the same as in the Dispatchable Dominant scenario. Upside opportunities for accelerated renewables and energy storage development are captured in the Renewables and Storage Rush scenario.

RENEWABLES AND STORAGE RUSH SCENARIO

The Renewables and Storage Rush Scenario illustrates the continued development of significant amounts of intermittent wind and solar generation resources by 2035 with limited new low-emitting thermal generation. This scenario also demonstrates a large penetration of energy storage development that plays an important role in managing the intermittent nature of renewables generation. The same trends impacting renewables development in the First-Mover Advantage Scenario represent signposts for wind and solar development in this scenario. For example, the continued drive toward Environmental, Social and Governance (ESG) objectives through the continuation of corporate PPAs, cost reductions and the simplicity of building known technologies that have short development times drive the growth. In this scenario, the development of energy storage would accelerate through potential storage cost declines, new revenue streams, supportive government initiatives, and technological improvements.

Compared to the First-Mover Advantage scenario, the most significant change is the inclusion of diverse energy storage technologies that will be required to support and balance intermittent energy supply. Recent activities that provide support to this scenario include Bill 22, the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act*,⁸ receiving royal assent with the expectation to become law later in 2022, and the federal government's commitment to establishing an investment tax credit for battery storage solutions.

The Renewables and Storage Rush Scenario assumes that there is limited thermal generation development, with significant renewables and energy storage developing to reliably meet demand. This was done in the modelling process by limiting the amount of thermal generation that the long-term capacity expansion tool could build, thereby allowing additional renewables and storage capacity to develop. Thermal generation development may be limited in the market due to higher costs than assumed, low operational performance or regulatory restrictions. The AESO considered developing a 100 per cent renewables-plus-storage supply-mix scenario; however, stakeholder feedback—as well as a preliminary high-level assessment—indicated that this level of renewables supply would be impractical from both a cost and operational standpoint for 2035.

This scenario sees near-term additions from renewables, cogeneration, and combined-cycle units in the early 2020s. As existing gas boiler units begin to retire in the late 2020s and as load increases, new wind and solar generation and energy storage begin to develop. This development is most pronounced in the early 2030s as the system progresses toward net-zero carbon emissions and as load increases due to electrification. In this scenario, short-term energy storage is key to managing the daily fluctuation in the solar output, moving energy from mid-day to the evening, or into the next morning. Longer-term storage is typically responsive to net demand (demand less wind and solar), moving renewable energy from extended periods of low net demand to periods of high net demand. Thermal hydrogen-fired simple-cycle develops in the early 2030s, also supporting increases in demand and generation retirements. By 2035, overall emissions are reduced to low levels that can be mitigated to net-zero levels using offsets or other forms of carbon management.

In addition to the renewables development signposts addressed in the First-Mover Advantage scenario, there are risks associated with the development of energy storage, including that cost reductions in the energy storage assets may not transpire, technological innovation may slow, and locations and economics for long-duration storage may be limited.

⁸ <https://www.alberta.ca/modernizing-albertas-electricity-system.aspx#:~:text=Bill%2022%2C%20the%20Electricity%20Statutes,the%20evolving%20needs%20of%20consumers.>

OPTION VALUE OF CONVERTED COAL-TO-GAS UNITS AND OTHER UNABATED THERMAL UNITS

In all three net-zero scenarios, the AESO has made assumptions regarding the retirement dates of coal-to-gas converted units. Compared to the maximum life extension that these units receive through regulation, the AESO's net-zero scenario retirement assumptions are earlier. Outside of the regulated retirement dates, facility owners will make decisions regarding the ultimate retirement of these assets.



“In addition, the AESO scenarios have other unabated thermal assets retiring prior to 2035. These assets could also extend their operating life based on owner decisions. It is expected that as a risk mitigation to these scenarios, if new large-scale low-carbon combined-cycle units are delayed, the converted coal-to-gas units—or other unabated thermal units—could remain available for economic purposes.”

This optionality also benefits electricity consumers from a reliability perspective. However, the federal government's development of the Clean Electricity Standard may impose new regulatory constraints to the operation of these legacy assets via emissions standards for natural gas-fired electricity production.⁹

ALTERNATIVES CHALLENGED TO BE ACHIEVABLE BY 2035

Several alternative decarbonization technologies could enable a net-zero carbon emissions transition in Alberta's electricity sector. However, options such as hydroelectric generation, nuclear development and additional transmission interconnections with neighbouring provinces may require long development timelines that could make it challenging to meet the 2035 electricity sector decarbonization objectives. The AESO included the hydro and nuclear alternatives as resource candidates in its net-zero emissions pathways modelling, but the market-driven development of these alternatives was not indicated in the three scenarios due to their comparative economics when contrasted with other low-emitting technologies. The AESO has not included any additional transmission lines interconnecting Alberta to neighbouring jurisdictions in any of the current analysis scenarios.

Hydroelectric

Alberta has significant hydroelectric resources available on the Slave River, Athabasca River, Peace River, North Saskatchewan River, and South Saskatchewan River. A 2010 study prepared for the AUC by Hatch Energy identified approximately 42,000 GWh per year of remaining developable hydroelectric energy potential at identified sites.¹⁰ This volume of energy could be sufficient to serve a significant amount of Alberta's load and therefore play a meaningful role in the decarbonization of the province's electric system.

Despite the large resource potential, Alberta's energy-only market framework has thus far attracted limited investment of hydroelectric generation. The long development timelines, large infrastructure development needs, and capital costs present investment risk hurdles that are not easily overcome without financial support, guarantees, or long-term contracts.

⁹ <https://www.canada.ca/en/environment-climate-change/news/2022/03/canada-launches-consultations-on-a-clean-electricity-standard-to-achieve-a-net-zero-emissions-grid-by-2035.html>

¹⁰ Hatch "Final Report for Alberta Utilities Commission: Update on Alberta's Hydroelectric Energy Resources". Rev 1. February 26, 2010. Pg 79, Table 10.

Nuclear or Small Modular Reactors

Nuclear fission technologies include large-scale reactors and small modular reactors. These technologies have not been deployed in Alberta and they are expected to require significant regulatory and construction timelines to permit and commercialize. As such, they may struggle to achieve decarbonization objectives within the 2035 timeframe. Nuclear facilities tend to have relatively high capital costs compared to other generation technologies. The long development timelines and high capital costs challenge merchant power investment in nuclear-fission generation technology. Financial support, financial guarantees, or long-term contracts are likely required to develop nuclear fission power stations in Alberta at the time of publishing this report.

Transmission Interconnections

Increasing the pathways for energy trade with neighbouring low-carbon jurisdictions could enable incremental two-way clean energy flows. Transmission assets connecting provinces and neighbouring jurisdictions create pathways for electricity transmission, but excess low-carbon generation capacity is still required from the exporting market in order to create a viable decarbonization solution. Given the monopoly and monopsony nature of Alberta's neighbouring markets, competition and fairness concerns could arise with significant expansion of import/export capacity from the AIES. Pathways to the east are limited and complicated by a lack of synchronization between the Midwest Reliability Organization and the Western Electricity Coordinating Council. Additional pathways to the west of Alberta are hindered by complex alpine environments, limited routes, sensitive environments, and technical requirements. For increased transmission capacity to assist in the decarbonization of the AIES, an excess of low-emission generation must also exist in the neighbouring market. The challenges arising from increased interjurisdictional transmission infrastructure would require coordination and support from governments, regulators, and system operators. Any significant decarbonization of Alberta's electric system achieved by increased interjurisdictional transmission capacity will likely require government support by the way of financing and approvals.

Electrification Pathways

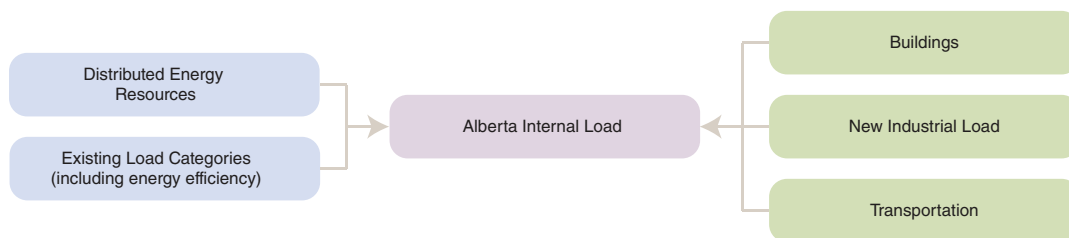


To assess the potential impacts of the net-zero transformation on electricity demand, the AESO developed a single Alberta Internal Load (AIL) forecast to represent a future with increased electrification and penetration of low-emitting distributed energy resources (DERs). This consistent AIL forecast is then used in the three scenarios that study a net-zero supply mix. Sensitivities to the load forecast are also assessed to test the impact and directionality of different load drivers. These sensitivities in turn inform the AESO's signposts. The AESO also captures the uncertainty of demand transmission service (DTS) load that could unfold in a net-zero future via plausible ranges. Each of these areas of analysis is further detailed below, starting with methodology and assumptions.

ENHANCEMENTS IN LOAD FORECAST METHODOLOGY

The AESO load forecast is a multi-step process that assesses load drivers separately before aggregating all the components into a single projection for the AIL.

FIGURE 1: AIL Forecast Components



Note: Blue-shaded drivers are load forecast components that were explained in detail in the 2021 LTO. Green-shaded drivers are components refined (transportation) or newly developed (buildings, new industrials) for the purposes of the AESO's Net-Zero Pathways Analysis.

The AESO's existing load categories and DERs forecast maintains the methodological approach taken in the 2021 LTO.¹¹ To complement the base forecast with the electrification potential of the broader economy, the AESO took a sector-by-sector modelling approach. A sectoral approach allows for the identification of unique drivers that set the pace and magnitude of increased load in a net-zero future. After consultation with stakeholders and review of other net-zero studies, the AESO developed three sectoral electrification models: transportation, buildings, and new industrial activity. The following sub-sections describe the modelling and key assumptions adopted for each of the AIL components.

¹¹ See Sections 3.3.2 Load Forecast Methodology and 3.3.4 DER Forecasting Methodology of the 2021 LTO here: <https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf>

Existing Load Categories

Existing load categories is the largest component of AIL and it broadly represents all the pre-net-zero energy consumption categories whose growth is driven by demographic, economic and energy sector outlooks. The existing load categories model incorporates historical trend, macroeconomic, oil sands production, energy efficiency and other explanatory variables.

The impact of net-zero policies and trends to Alberta's macroeconomic landscape remains uncertain. Some commentators view a net-zero future as a detriment to traditional sectors, others view it as an opportunity for economic diversification and growth, while a third group has a perspective that balances the first two views. The AESO relied on a single macroeconomic scenario (which includes economic, employment and population data) from the Conference Board of Canada's long-term outlook, *Alberta's Energy and Demographic Prospects to Weaken: Alberta's Outlook to 2045*, released in early 2022.¹² The macroeconomic outlook captures the near-term rebound of the Alberta economy from the dual shocks of the COVID-19 pandemic and oil price volatility from 2020-2022. Over the longer term, provincial economic growth is expected to be moderate due to the combination of an aging population and a slowdown in oil production post-2030.

The specific impact of net-zero policies on oil sands production, particularly the implementation of the federal 2030 ERP and other policy or corporate net-zero announcements, remains difficult to ascertain at the time of writing this report.¹³ During stakeholder consultations, the AESO received diverging views on what a net-zero future means for the oil sands sector. Some assume that an emissions cap and subsequent decarbonization policies will lead to a production cap or eventual decline, while others predict that oil and gas production can be maintained or increased if the sector improves its carbon intensity through CCS and championing other decarbonization efforts. Based on these wide-ranging views, the AESO relied on IHS Markit for its reference outlook¹⁴ and then developed two sensitivity scenarios to assess uncertainty of the oil sands sector and its corresponding impact on Alberta electricity demand.¹⁵ The outlook from IHS Markit, released in 2021, suggested that oil sands production will grow at a moderate pace (aided by the ramp-up of existing operations, optimization, and completion of projects where some capital has already been invested), but assumes no further greenfield, capital-intensive long lead-time development projects. In addition to the IHS Markit oil sands outlook, the AESO developed two sensitivity scenarios that test stakeholders' views. The first sensitivity tests a +/- 500,000 barrels-per-day differential to the IHS Markit oil sands outlook to assess the directionality and relative magnitude of increased/decreased production in 2035. The second sensitivity assesses the incremental station service (auxiliary) load in 2035 associated with CCS installations at cogeneration facilities.

¹² The Conference Board of Canada's outlook can be found here: <https://www.conferenceboard.ca/e-library/abstract.aspx?did=11457>

¹³ Adding to this list is geopolitical and energy security discussions that could impact the near- and long-term growth of Canada's energy sector.

¹⁴ IHS Markit, now S&P Global, maintains three bottom-up long-term outlooks including the reference case as well as three back-casted net-zero long-term outlooks.

¹⁵ Figure 10: Impact Sensitivity by Load Driver (Impact to Average Load in 2035)

Net-zero studies and commentators often focus on the importance of minimizing energy demand growth through energy efficiency improvements to reach a net-zero grid.¹⁶ In 2018, Energy Efficiency Alberta suggested that there is around 7,000 GWh of potential energy savings by 2038 if there is a steady deployment of energy efficiency measures starting in 2019. The report warns that the effectiveness and pace of these measures depend on several factors, including government incentive levels, market effectiveness, duration of energy efficiency measures, and customer willingness to adopt, among others.¹⁷ The AESO's approach to energy efficiency is based on a simplified analysis of the rate of energy intensity of the Alberta economy observed during the past two decades.¹⁸ The AESO developed a sensitivity (testing energy efficiency gains growing at three times the historical growth rate assumed in the base model) to assess the impact of more accelerated energy efficiency improvements (whether directly incented by policy and government programs or indirectly via carbon pricing exposure).¹⁹

Distributed Energy Resources (DERs)

In the Alberta wholesale market, energy from resources with a capacity under 5 MW and connected at the distribution level offset AIL. Alberta currently enjoys a diverse sub-5 MW-DER supply mix.²⁰ For this analysis, the AESO focused on the three key technologies (solar, gas and wind) that not only dominate today's landscape but are anticipated to be impacted by net-zero policies and trends. The modelling assumptions of these technologies do not deviate materially from the approach described in the 2021 LTO,²¹ with the only exception related to installed capacity growth. Solar DER growth is driven by declining capital costs and increased consumer preferences. Wind DER penetration is moderate since its economics tend to favour economies of scale that come with sites larger than 5 MW. Gas DER capacity is assumed to slow down compared to recent years due to regulatory changes as well as increased carbon tax exposure in a net-zero future.

Transportation

When it comes to decarbonization of the economy, the transportation sector has the benefit of commercialized technologies and ongoing growth in supporting infrastructure to facilitate the transition, particularly for light-duty passenger vehicles (e.g., cars, SUVs, minivans, and pickup trucks), freight (e.g., medium- and heavy-duty vehicles) transport, and buses (transit, school, coach). Decarbonizing these vehicle classes may increase overall electric energy demand depending on the most suitable technology; for example, battery-electric vehicles may be suitable for light-duty and shorter-range types of freight transport and buses, while other type of zero-emission vehicles may be suitable for longer haul and heavier payload capacity use cases.

¹⁶ International Energy Agency (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector, PDF pg. 66-67, URL: <https://www.iea.org/reports/net-zero-by-2050>; International Energy Agency (2022), Canada 2022: Energy Policy Review, PDF pg. 80-107, URL: <https://www.iea.org/reports/canada-2022>

¹⁷ See PDF pg. 32-33 of Navigant (2018), Energy Efficiency Alberta: 2019-2038 Energy Efficiency and Small-Scale Renewables Potential Study, URL: <https://open.alberta.ca/publications/energy-efficiency-alberta-2019-2038-energy-efficiency-and-small-scale-renewables-potential-study>

¹⁸ This assumption is in line with the methodological approach adopted in the 2021 LTO, see PDF pg. 8 under section 3.2.1.2 Economic Recovery.

¹⁹ The AESO adopted a sensitivity of generalized three times historical rates based on stakeholder feedback and approach taken by IEA (2021).

²⁰ For a summary of Alberta's DER mix, see the AESO's monthly Micro- and Small-Distributed Generation report available at: <https://www.aeso.ca/market/market-and-system-reporting/micro-and-small-distributed-generation-reporting/>

²¹ See Table 3 DER Energy and Geographical Assumptions in PDF pg. 17.

The AESO's model is designed to test a high boundary of EV penetration in Alberta, represented by a “policy leads, everything else follows” approach to modelling. This means that EV projections are assumed to meet policy goals announced in the federal 2030 ERP regardless of EV availability, cost parity with non-EV choices, transmission and distribution system readiness, public and private charging optionality, regulatory, and incentives for zero-emission commercial and institutional fleet, etc. The AESO's model focuses on four vehicle classes (light-duty, medium-duty, heavy-duty, and buses), which are described in detail next. Sensitivities were developed to test slower and faster adoption rates than assumed for the net-zero load forecast.²²

Light-duty Vehicles (LDVs)

Annual penetration level is assumed to meet federal policy intentions identified in the 2030 ERP for new sales requirements—i.e., 20 per cent by 2026, 60 per cent by 2030, and 100 per cent from 2035 onwards.²³ Note that the federal requirement is for zero-emissions vehicles (ZEVs),²⁴ but to test a high-electrification bookend the AESO assumes that all new light-duty zero-emissions vehicles will be battery-electric. Further, the current plug-in hybrid vehicle fleet in Alberta is included, but the model assumes no further growth of this vehicle sub-class and its lifecycle replacement is assumed to be battery-electric vehicles. Given near-term electric vehicle availability and choices, the model assumes greater uptake of light-duty passenger cars in the 2020s, while light-duty trucks (which also includes minivans and sport-utility vehicles) will increase in prevalence in the 2030s to the car/truck ratio historically seen in Alberta with internal-combustion engine types.²⁵ Vehicle charging specifications (e.g., battery size, kWh/km efficiency rates, charging duration) are based on representative battery-electric cars and trucks;²⁶ these are considered static over the forecast period and no assumption is made around performance changes to vehicle charging or charging infrastructure and equipment (e.g., enhancements to connector types, power ratings, etc.). Daily charging needs are based on typical Alberta driving patterns and mileage; these are considered static over time and no assumption is made around changing driving behaviour. Daily charging profiles assume a hybrid of daytime and nighttime charging (i.e., a combination of workplace and home-based charging) with limited intervention or charging coordination to avoid coincidental EV charging and regular load peaking. An EV charging sensitivity was created to shift EV charging peaks to past midnight hours; this is discussed in more detail in the section below, which speaks to the resource adequacy results and is represented in Figure 2: EV Charging Profiles. Charging values are adjusted by season (winter and summer) and day type (weekday vs weekend); no adjustments are made for holiday or non-typical driving patterns.

²² See results in Figure 10: Impact Sensitivity by Load Driver (Impact to Average Load in 2035).

²³ See PDF pg. 63 of the 2030 ERP.

²⁴ ZEVs are defined as vehicles with energy sourced as battery-electric, plugged-in hybrid electric, or hydrogen fuel cell; see PDF pg. 57 of the 2030 ERP.

²⁵ The AESO estimates a 20/80 split between passenger cars and trucks based on estimates of new sales in 2017-2021.

²⁶ The AESO relied on electric vehicle specifications and annual mileage intelligence produced by Dunsky Energy + Climate Advisors in an EV integration report produced for EPCOR. The AESO thanks Dunsky and EPCOR for their permission to use this data. The AESO remains responsible for data curation, transformation, error, or omissions.

Medium-duty Vehicles (MDV)

Annual growth is based on the federal ERP but assumes other low- and zero-emission technologies (e.g., hydrogen fuel cell, biodiesel, renewable natural gas) will compete with battery-electric vehicles.²⁷ As such, the AESO model assumes the following percentages of new MDV sales are battery-electric: 14 per cent by 2030, 22 per cent by 2035, and 30 per cent from 2040 onwards. Vehicle charging specifications are based on representative battery-electric urban delivery and utility vehicles, and these remain static. Driving patterns and daily charging needs are assumed to be reflective of short-haul urban operations, and an assumed nightly return-to-depot charging (e.g., no public or on-road charging) profile. The EV charging sensitivity described above also modifies the profile for medium-duty electric vehicles by assuming daytime on-road charging (more details in the resource adequacy results and represented in Figure 2: EV Charging Profiles). Charging values are adjusted by season but maintained regardless of day of the week or holidays.

Heavy-duty Vehicles (HDV)

Annual vehicle projections are treated similarly as MDV by assuming that non-battery electric alternatives will be used to meet the federal ERP targets.²⁸ The AESO model assumes the following percentages of new HDV sales are battery-electric: nine per cent by 2030, 15 per cent by 2035, and 20 per cent from 2040 onwards. HDV is represented with a lower penetration level, compared to the medium-duty class, to reflect that this vehicle class generally requires longer duration, longer haul, and heavier payload capacity which are currently limiting features of battery-electric technology and where other zero-emission fuel sources may present greater potential (including better total cost of ownership comparison to diesel choices).²⁹ Vehicle charging specifications and daily charging needs are based on representative battery-electric short-haul trucks, and these are maintained static. Given limited known-use cases of electric HDVs in Alberta, the AESO assumes that this EV class will be primarily for short-haul regional operations that serve multiple schedules (i.e., food and beverage delivery and warehouse transportation) and therefore has a spread-out depot-based charging profile.³⁰

Buses

Annual electric growth differs based on sub-classes. Transit bus electrification is based on the federal ERP goal to reach 100 per cent of new sales by 2040.³¹ Other bus types (e.g., coach, school) have different use cases and therefore varying range needs which may not all be suitable for battery-electric;³² as such, the AESO assumes that 60-65 per cent of new sales are battery electric from 2030 onwards. Vehicle charging specifications and daily charging needs are based on representative battery-electric buses for each sub-class, and these are maintained static over the forecast period. Given the heavier presence of transit buses in the overall electric bus fleet, the charging profile has a bi-modal shape, with morning and evening peaks to reflect depot-based charging following peak-transit periods.³³

²⁷ The federal ERP states a goal of 35 per cent of new sales of medium- and heavy-duty vehicles (MHDV) be ZEVs by 2030 and develop regulations for a certain subset of MHDVs sales be 100 per cent ZEVs by 2040. See PDF pg. 63 of the 2030 ERP.

²⁸ See footnote 27.

²⁹ See Ledna et al (2022), Decarbonizing Medium and Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis, URL: <https://www.nrel.gov/docs/fy22osti/82081.pdf>

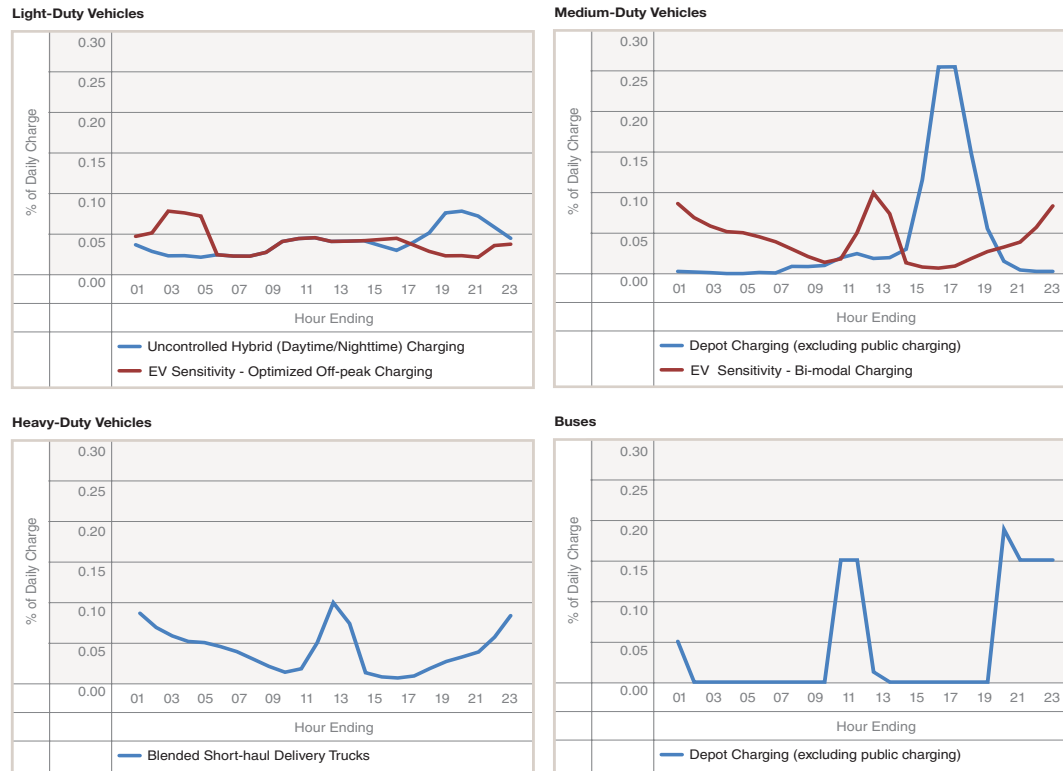
³⁰ AESO blended the depot-charging profiles published by Borlaug et al (2021), Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems, URL: <https://data.nrel.gov/submissions/162>

³¹ See PDF pg. 230 of the 2030 ERP.

³² See Burns & McDonell (2021), On the Road to Fleet Electrification with Foothill Transit (Webinar), URL: <https://info.burnsmcd.com/electrification/on-the-road-to-fleet-electrification-with-foothill-transit>

³³ The AESO adopted charging observations from a pilot study for the Edmonton Transit System feasibility, see Marcon (2016), Electric Bus Feasibility Study for the City of Edmonton, URL: https://www.edmonton.ca/public-files/assets/document?path=transit/ets_electric_feasibility_study.pdf

FIGURE 2: Electric Vehicle Charging Profiles



Buildings

The decarbonization and transformation of the energy required to heat and cool buildings can have a significant impact on Alberta’s electricity load and, to some extent, on supply (in the form of distributed energy resources). Buildings have the benefit of a defined decarbonization toolbox: electrification of heating systems via “fuel-switching” from natural gas to electric heat pumps; enhancements to energy efficiency (upgrading building envelope, improving insulation ratings; replacing windows and doors; greater air sealing; replacing lighting and appliances, etc.); and reducing embodied carbon in construction materials. However, the implementation of this set of net-zero solutions is challenged by the lack of regulatory direction (i.e., lack of low-carbon oriented building codes for new and retrofit buildings), limited government incentives/grants to enable fuel switching or energy efficiency upgrades, etc.³⁴ The federal 2030 ERP acknowledged these implementation barriers and announced a policy agenda that includes, among other measures, the development of a national net-zero by 2050 buildings strategy for which more details will be released in 2023.³⁵

³⁴ For an analysis of regulatory and investment barriers to decarbonize buildings, see Pembina (2020), Achieving Canada’s climate and housing goals through building retrofits, URL: <https://www.pembina.org/reports/federal-buildings-recs-2020.pdf>

³⁵ See PDF pg. 38 and 246 of the 2030 ERP (<https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf>)

Given the long turnover rate to retrofit existing buildings and the lack of regulatory clarity (i.e., targets, timelines, mandatory versus optional requirements within the proposed federal net-zero building code), the AESO's building electrification model includes simplified assumptions around uptake and timelines that start in 2030 to allow for greater policy certainty to unfold (whether at the federal, provincial or municipal level) as well as improved cost parity between electric heat pumps and natural gas-based boilers.³⁶ The model only focuses on quantifying the electrification increase due to the fuel-switching of space and water heating systems. Sensitivities were developed to show the effect of faster/slower fuel-switching on the 2035 net-zero load forecast.³⁷ Energy efficiency improvements related to space and water heating intensity are kept in line with historical rates in Alberta; no other changes to energy efficiency are modelled.

Due to Alberta's long, cold winters, ground-source heat pumps are selected over air-source heat pumps, since ground-source systems can operate more efficiently, in that they take advantage of warmer and more stable ground temperatures.³⁸ Heat pump installation is modelled based on an adoption S-curve that assumes a 100 per cent penetration in residential, commercial, and institutional buildings by 2050; industrial, agricultural and other types of buildings are not included in the model. The assumed coefficient of performance—the rate of thermal (heat) energy produced to the electrical energy used—is 3.0, which aligns with Alberta-based feasibility studies;³⁹ this rate is kept static over the forecast period. Although heat pumps provide the additional benefit of cooling buildings, the model excludes the impact to Alberta's air conditioning (AC) stock and electrical load given how limited AC penetration is in the province.⁴⁰ The load impact of supplementary heating systems is not included in the model.⁴¹

The model does not include on-site generation (e.g., DERs), demand-side management technologies, or energy efficiency upgrades that may be driven in parallel by building decarbonization policies.

³⁶ The leveled cost of heating differentials between electric heat pumps vs natural gas boilers depend on several factors: expected heat demand, forward electricity and natural gas prices, carbon prices and expected impact on pool price and natural gas forwards, upfront capital costs, operating costs, technology lifetime, etc.

³⁷ See results in Figure 10: Impact Sensitivity by Load Driver (Impact to Average Load in 2035).

³⁸ See Natural Resources Canada (accessed April 2022), Heating and Cooling with a Heat Pump; URL: <https://www.nrcan.gc.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817#o1>

³⁹ See Dave Miller and Tanya Mayes (2008), Feasibility of Ground Source Heat Pumps in Alberta; URL: http://greenedmonton.ca/files/GSHP_DiscussionPaper_CCC_Alberta.pdf

⁴⁰ Expected AC penetration and load could impact the uptake and use of heat pumps in the future. Although Alberta has low AC penetration, this is expected to increase with rising temperatures due to climate change (see Rivers and Schaffer (2020), *Stretching the Duck: How Rising Temperatures will Change the Level and Shape of Future Electricity Consumption*, Energy Journal Vol. 40; URL: <https://doi.org/10.5547/01956574.41.5.nriv>). The AESO will continue to monitor and conduct research on the pace, likelihood and impact of AC and heat pump adoption in subsequent long-term forecasts.

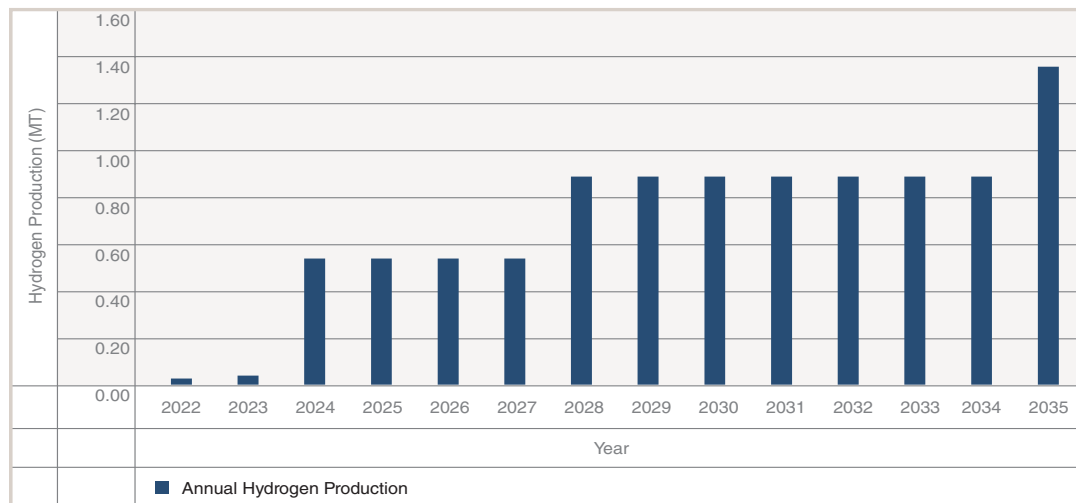
⁴¹ Depending on configuration and equipment rated capacity, heat pumps may have a limited ability to heat buildings during very cold temperatures. To address this, heat pump installations are usually supplemented with an all-electric (electric baseboards) or a hybrid (gas furnaces or boilers) system. For more details, see Natural Resources Canada (accessed April 2022), Heating and Cooling with a Heat Pump; URL: <https://www.nrcan.gc.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817#z2>

New Industrial Activities

Reducing emissions from industrial heat and electricity use will be crucial to reaching economy-wide net-zero emissions in Alberta. A promising technology is the increased use of energy carriers, such as hydrogen, if it can be produced in a low-carbon manner via CCS or other technologies. Hydrogen production with low carbon emissions can accelerate decarbonization efforts if used as an input fuel for combustion by large industrial emitters (e.g., heavy oil upgrading and oil refining sectors, chemical sectors, and forestry sectors), especially in Alberta. The production of hydrogen, whether it is based on electrolysis (green) or natural gas-reforming (blue) technologies, is expected to increase industrial load in Alberta. Although hydrogen production via electrolysis would not require CCS, this production method requires significant upfront capital and commands higher operating cost relative to natural gas-reforming technologies; these factors make electrolysis a less competitive alternative for large industrial emitters in Alberta. The AESO’s industrial load model focuses on assessing the incremental energy consumption related to hydrogen production with CCS and assumes natural gas-reforming technologies, such as steam methane reforming and autothermal reforming (ATR), being the economically preferred hydrogen production processes in Alberta until 2035.⁴²

To estimate hydrogen production, the AESO looks at Alberta’s near-term major hydrogen projects (included in the AESO’s project list) by 2030 and relies on the Canada Energy Regulator’s *Canada’s Energy Future 2021 report*⁴³ on projected long-term hydrogen production post-2030. Figure 3 illustrates the resulting total annual hydrogen production in Alberta from 2022-2035.

FIGURE 3: Alberta Hydrogen Production

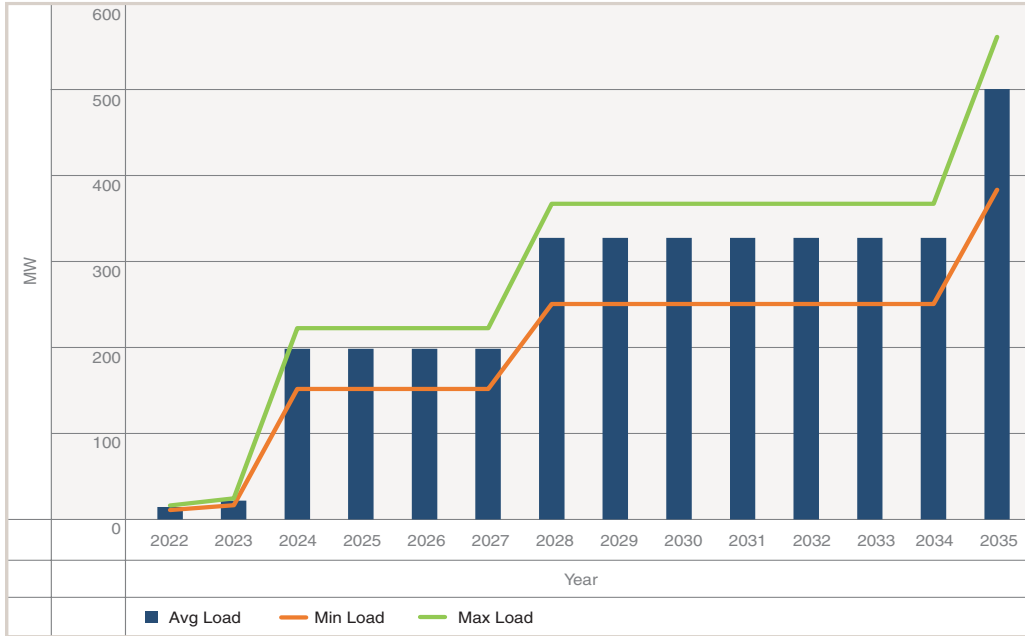


The unit energy consumption for hydrogen production at industrial sites would depend on the type of technology used (steam methane reforming or ATR process), and the share of each technology in producing hydrogen with CCS. The forecast does not make explicit assumptions on whether the hydrogen load is consumed on site or from the grid, but it is generally expected that there would be an incentive to consume on site to take advantage of cogeneration opportunities in the production process. The figure below shows estimated annual energy consumption from hydrogen production.

⁴² The assumption relied on Alberta Hydrogen Roadmap on the possible emerging hydrogen production technologies until 2035. The report can be found via <https://www.alberta.ca/hydrogen-roadmap.aspx>

⁴³ See Canada’s Energy Future 2021 report here; URL: <https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/index.html>

FIGURE 4: Incremental Industrial Load from Hydrogen Production



In addition to hydrogen production, electrification of heavy industries (includes mining and manufacturing of various industrial and commercial products, such as metals, chemicals and fertilizers, cement, iron and steel, and pulp and paper) could also result in higher load growth in Alberta. However, the extent to which electricity will play a role in the decarbonization pathway to heavy industries, particularly with respect to magnitude and pace, remains uncertain. The limited impact of heavy industry electrification by 2030 is also evident in the federal 2030 ERP modelling methodology.⁴⁴ The AESO assumes heavy-industry electrification will be maintained in line with the historical relationship observed with economic and energy sector growth. The AESO also developed a sensitivity scenario testing 25-50 per cent adoption of CCS in the cogeneration sector, which includes heavy industrial loads in addition to energy (oil sands, conventional oil and gas) loads.

LOAD FORECAST

In the 2021 LTO, the AESO provided an initial attempt at quantifying net-zero drivers of load based on information available at the time. The load forecast included in the Reference Case and Clean-Tech scenarios had assumptions regarding increased electrification of the transportation sector and increased penetration of renewable sub-5 MW DERs (particularly solar). For the AESO Net-Zero Report, the AESO refined transportation and sub-5 MW DER modelling and added other sectors expected to grow in an electrified and decarbonized future (building heating systems and new industrial load from hydrogen production). The combined effect of sectoral electrification and growth in DERs in the AESO Net-Zero Report is markedly higher than the 2021 LTO scenarios by six to seven per cent in 2035. Growth in this forecast through 2035 is moderate (at 0.9 per cent per year) thanks to gradual increases in EVs and hydrogen production, and continues to grow more robustly (at 1.5 per cent per year) post-2035 once building heating electrification increasingly adds to the maturation of electric transportation across multiple segments (greater medium- and heavy-duty vehicles) and expansions to hydrogen production take place.

⁴⁴ See PDF pg. 230 of the 2030 ERP.

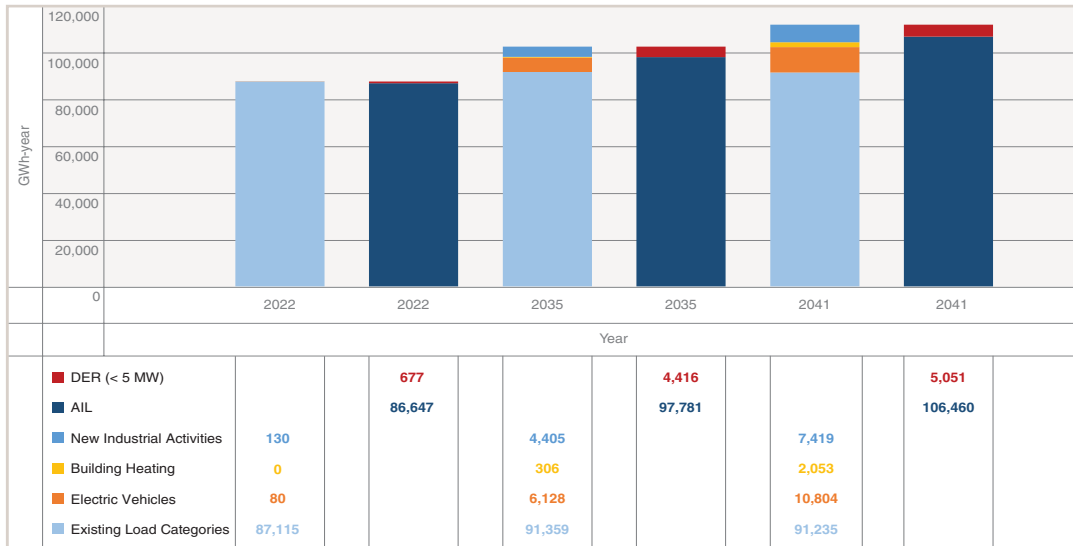
“Compared to actual AIL observed in 2021, the AESO Net-Zero Report forecast demonstrates that load is expected to increase by 12,567 GWh (15 per cent) by 2035 and 21,246 GWh (25 per cent) by 2041. These expected increases in load are lower than observed growth in Alberta over the past 20 years. The load forecast is projecting annual growth of 1.1 per cent in 2022-2041 compared to 1.9 per cent in 2002-2021.”

FIGURE 5: AIL Energy Forecast



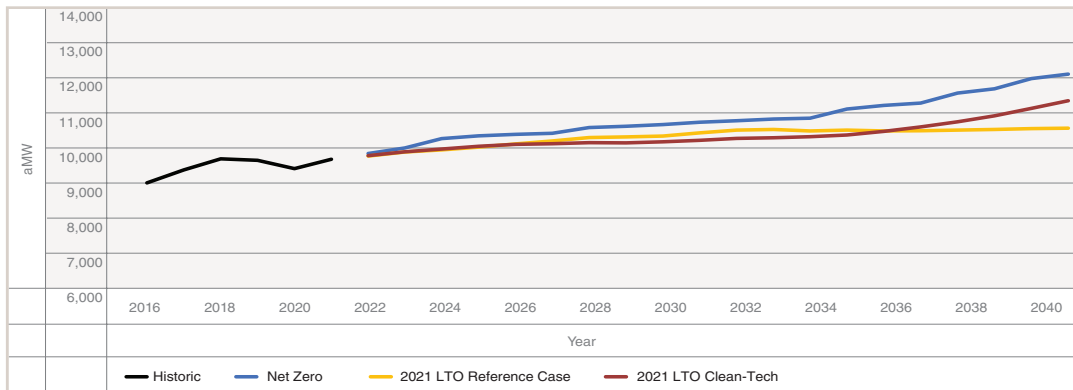
Despite increased sub-5 MW DER penetration, electrification and new industrial load drive energy consumption increases to AIL over the next two decades. Figure 6 illustrates the individual energy levels of the load components that compose AIL for select years (2022, 2035, and 2041). The first bar of each year stacks up the energy attributed to existing load categories (load driven by demographics, economics and energy sector growth), EVs, building heating systems, and hydrogen industrial activities. The second bar of each year shows the offsetting effect of sub-5 MW DERs (by lowering the total from the first bar) which leads to the final expected AIL level. The chart demonstrates that, although sub-5 MW DER energy offsets the rest of the components except for existing load categories in 2022, sub-5 MW DER energy will be less dominant in the 2030s-2040s. The entirety of sub-5 MW DER energy is more than offset by the increased load required to charge EVs in the mid-2030s. New industrial loads supporting decarbonization will also add to Alberta energy demand, especially at the turn of the decade and is expected to continue to increase up to 2041. Electrification of heating systems in buildings shows a minimal impact by 2035, with increasingly greater impact by 2041 as fuel-switching grows in scale.

FIGURE 6: AIL Breakdown in Select Years



The continued evolution of electricity demand in the province in a net-zero future will introduce changes to typical (average) and highest-demand (peak) load. On an average hourly basis, the AESO Net-Zero Report demand forecast is higher than the 2021 LTO scenarios by six to seven per cent in 2035 and seven to 14 per cent in 2041.

FIGURE 7: Average AIL Demand Forecast

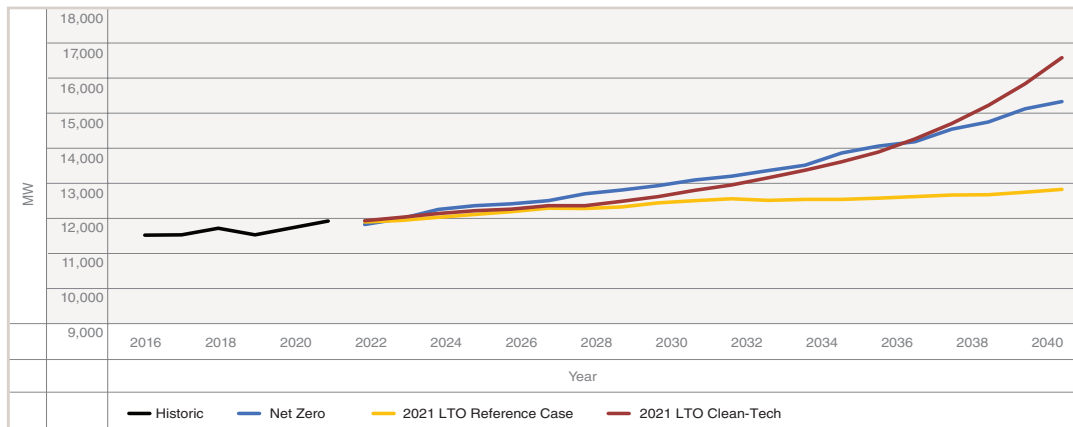


With respect to peak demand hours, the AESO Net-Zero Report demand forecast is higher than the 2021 LTO Reference Case by 12 per cent and Clean-Tech Scenario by two per cent in 2035. Over time, peaking conditions will become increasingly sensitive to EV charging profiles and building heating system cycles; the extent to which EV charging and heating load will overlap with other AIL drivers during on-peak winter hours is going to drive a lot more variability. In the AESO Net-Zero Report load forecast, the AESO refined EV charging profile assumptions by introducing a degree of demand side management that moderates the concentration of EV charging during evening hours, in contrast to the 2021 LTO assumption of unmanaged EV charging, and therefore leads to lower peaks in the late 2030s compared to the Clean-Tech Scenario's forecast.⁴⁵

⁴⁵ EV load management measures can be implemented in multiple formats: DFO-led direct-control load management programs, customer incentives, exposure to time-of-use rates or other price signals, or even EV manufacturer-led changes to improve ease and customer education regarding charging schedules. Regardless of the load management strategy, the objective remains the same: shifting charging loads from on-peak to off-peak hours. The AESO remains agnostic of whichever management strategy(ies) become adopted and these results should not be considered as a recommendation and/or evidence of their load shifting effectiveness.

“Compared to the 2021 peak, a future of increased electrification and renewables-intensive DERs are expected to result in peak AIL growth of 19 per cent by 2035 and 34 per cent by 2041.

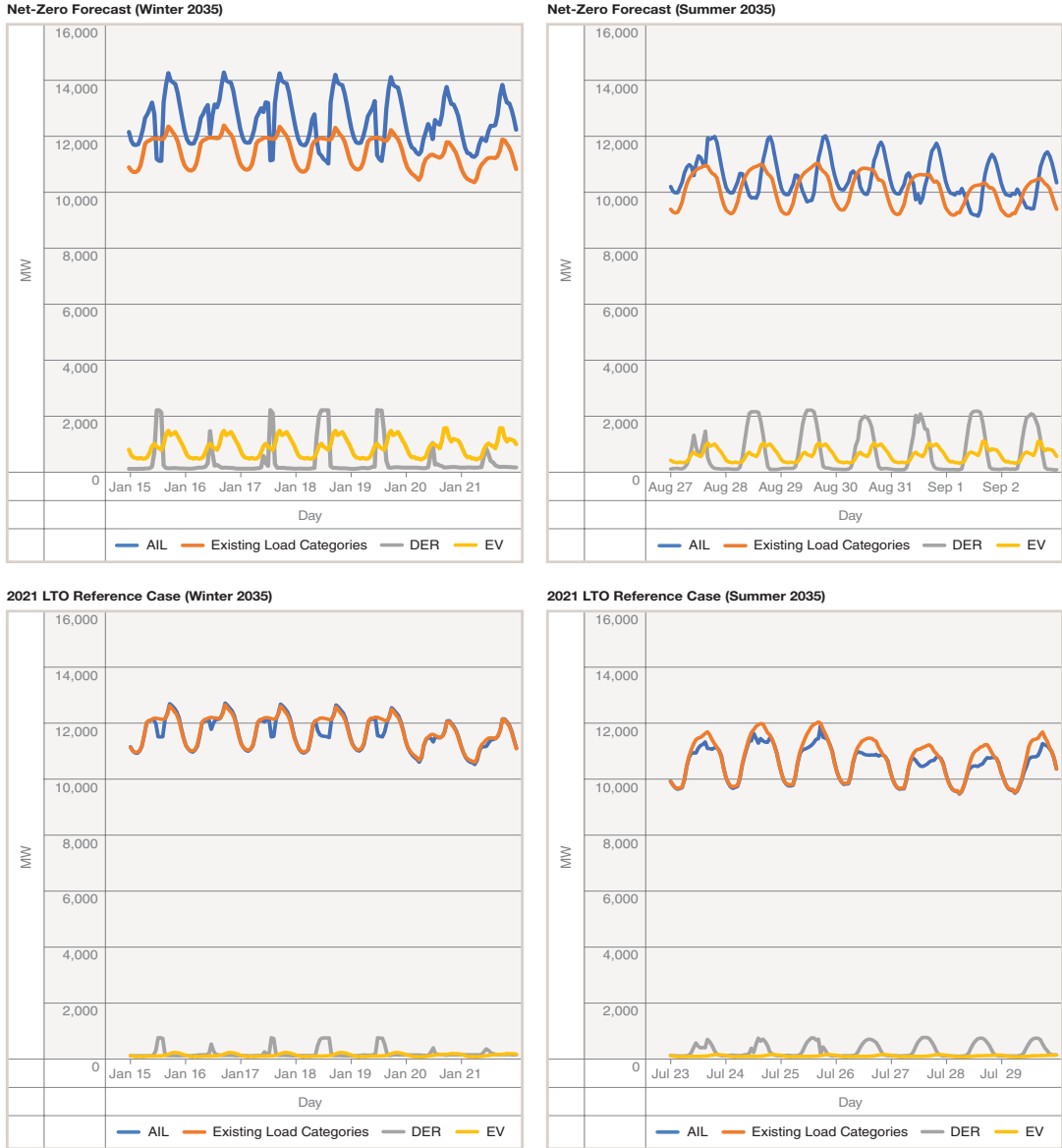
FIGURE 8: Peak AIL Forecast



A net-zero emissions future is expected to introduce seasonally distinct changes to the load shape historically observed in Alberta. The combination of high solar DERs and high adoption of EVs—two technologies with accelerating adoption in Alberta that come with unique seasonal and intra-day variations—will lead to greater AIL variability and greater frequency of non-typical daily shapes. Winter conditions will increasingly have more mid-day variability, depending on cloud coverage and precipitation conditions, which impact solar generation as well as increased evening peak loads due to EV charging. The diurnal energy profile of solar generation means that solar DERs will not offset most EV charging needs. Summer peaking conditions, conversely, will have slightly greater overlap between solar DER and EV charging during late afternoon/early evening hours but not entirely. Figure 9 illustrates how these expected seasonal changes to peaking conditions due to a net-zero future with greater electrification and DER penetration are markedly different from the 2021 LTO Reference Case. Based on these early insights of variability and load shapes in a net-zero future, the AESO expects that additional assessment of the operational impacts of the electrification and supply mix scenarios developed for the AESO Net-Zero Report will be required.⁴⁶

⁴⁶ For flexibility analyses of the 2021 LTO scenarios, see AESO the 2022 System Flexibility Assessment, URL: <https://www.aeso.ca/assets/2022-System-Flexibility-Assessment.pdf>

FIGURE 9: EV and DER Impact to AIL Shape during Winter and Summer Peaking Week Conditions in 2035 under the Net-Zero Emissions Pathways Forecast and the 2021 LTO Reference Case

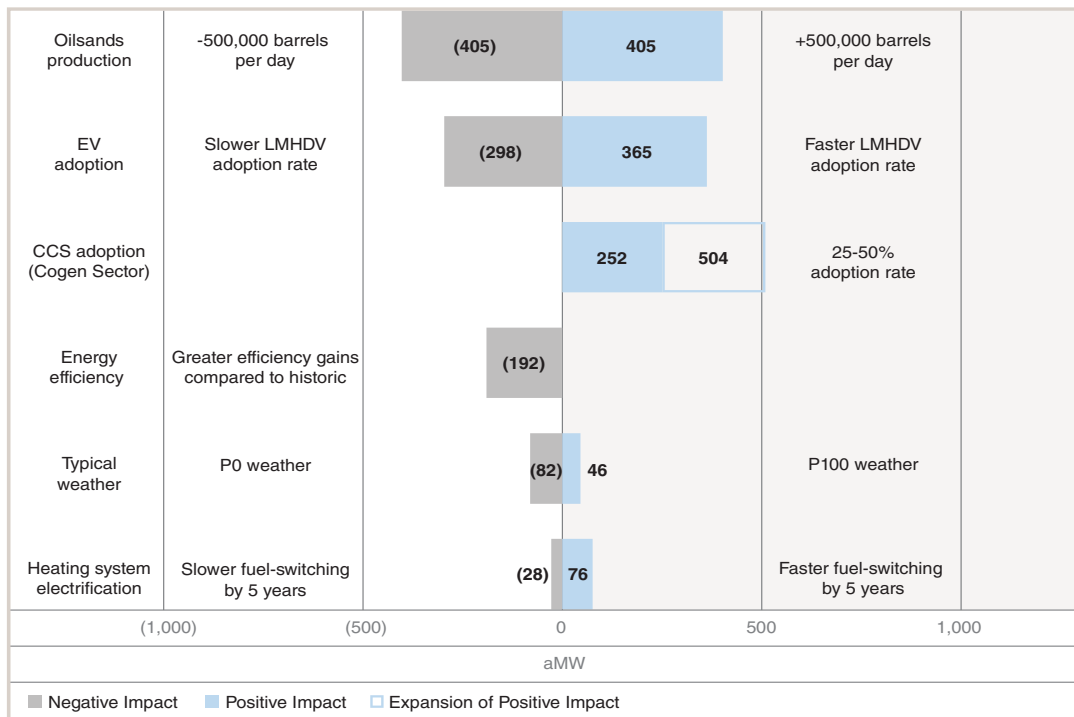


LOAD SENSITIVITIES AND ELECTRIFICATION SIGNPOSTS

The AESO has incorporated sensitivities for key load drivers to quantify the uncertainties in forecasting the timing, pace and magnitude of the key drivers (i.e., isolating the impact of one input at a time).⁴⁷

Figure 10 shows the directionality and magnitude of these sensitivities by load driver compared to base assumptions. The sensitivities are measured against the average load expected for 2035 (11,162 aMW). Although it is unlikely that all these sensitivities will materialize in parallel, the combination of them suggest that AIL in 2035 can be between 10,157 aMW (-1,005 aMW) and 12,306 aMW (+1,144 aMW).⁴⁸ Compared to actual AIL in 2021, this sensitivity range suggests that load in 2035 could be between four to 26 per cent higher.

FIGURE 10: Impact Sensitivity by Load Driver: Change in Average Load in 2035 (base of 11,162 aMW)



⁴⁷ Readers should be aware that the definition of these sensitivities do not represent the AESO's advice or preference of outcome. Rather they represent a plausible extreme or book-end scenario to test the isolated impact of any given load drivers.

⁴⁸ The upside risk is higher if CCS adoption in the cogeneration sector is greater than the assumed 25 per cent by 2035.

These sensitivities support the AESO in developing an informed view of the following signposts:

- Growth prospects of the energy sector in Alberta—oil sands production and energy intensity per barrel can impact industrial load in the province.
- Policies, subsidies and/or technological advancements incenting EV adoption—measures that increase/decrease electrification of transportation options and/or provide greater/fewer vehicle choices, especially in the energy-intensive MHDV class, can impact the growth and pace of EV charging loads.
- Decarbonization of industrial sectors with behind-the-fence (BTF) generation—post-combustion CCS adoption and its corresponding auxiliary load increase can have the dual effect of increasing industrial BTF load and lowering net-to-grid cogeneration output (see detailed discussion in Emissions Reduction Outcomes section).
- Changes to energy efficiency uptake—technological advancements, policy measures and/or customer preferences that accelerate gains in energy efficiency can lower AIL.
- Changes in average weather conditions—variations in the temperature profile for any given year can impact the most weather-sensitive load portion of AIL (e.g., residential, commercial, some industrial).
- Decarbonization of space/water heating systems in buildings—pace and timing of heat pump subsidy programs, policy changes (e.g., introduction of low-carbon-oriented building codes for new and retrofit buildings) and/or changes to the levelized cost of heating can affect the pace of load growth associated with buildings.

DEMAND TRANSMISSION SERVICE LOAD

Demand transmission service (DTS) load represents the largest component of system load in the province.⁴⁹ DTS load is relevant for understanding the volume of energy that mostly utilizes, and therefore pays for, Alberta's transmission system. Since 2010, AIL and DTS load have increased at a different pace due to an increase in BTF generation or self-supply growth.⁵⁰ The percentage of AIL that was attributed to DTS was 75 per cent in 2010; by 2021, that percentage was closer to 70.⁵¹

A net-zero future with increased sectoral electrification, higher industrial load and greater DERs may impact DTS growth and its ratio to AIL going forward in multiple ways. For instance, EV adoption and electrification of buildings may result in higher DTS load growth and a corresponding increase in the DTS-to-AIL ratio in the future. Alternatively, if electrification of other sectors is served by on-site generation and the expected increase in hydrogen load is mostly configured with BTF generation, this could lead to DTS load growth at a slower pace than AIL. In this scenario, the ratio of DTS to AIL can be expected to continue declining going forward.

Given the uncertainties of the DTS load growth, the AESO applied a simplified ratio-based approach to estimate possible DTS load over the forecast period. The ratio is based on a fixed range between 65-75 per cent of the single AIL forecast produced for the AESO Net-Zero Report.⁵² The range of DTS estimates represents different DTS growth paths as compared to the DTS estimates published in the 2021 LTO and later used for estimating the 2022 20-year transmission rates.⁵³

⁴⁹ Based on the AESO Consolidated Authoritative Document Glossary (<https://www.aeso.ca/assets/Consolidated-Authoritative-Document-Glossary-July-1-2021.pdf>), system load is defined as the total, in an hour, of all metered demands under Rate DTS, Rate FTS and Rate DOS of the ISO tariff plus transmission system losses.

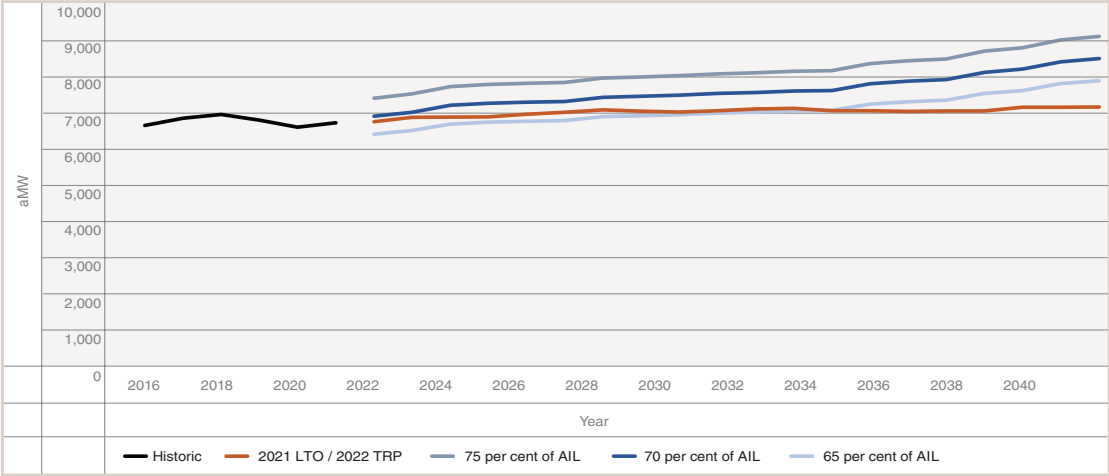
⁵⁰ For a detailed discussion of historical BTF load drivers, see PDF pg. 46 of the 2021 LTO.

⁵¹ For reference, the ratio of system load to AIL was 71 per cent 2021.

⁵² Readers should be cautious in adopting these DTS estimates for their analysis. These ranges do not represent a bottom-up DTS load forecast and therefore should not be interpreted as such.

⁵³ 2022 Transmission Rate Projections can be found here: <https://www.aeso.ca/grid/transmission-costs/>

FIGURE 11: DTS Estimates based on Simplified Ratio-based Approach



Supply Decarbonization Pathways



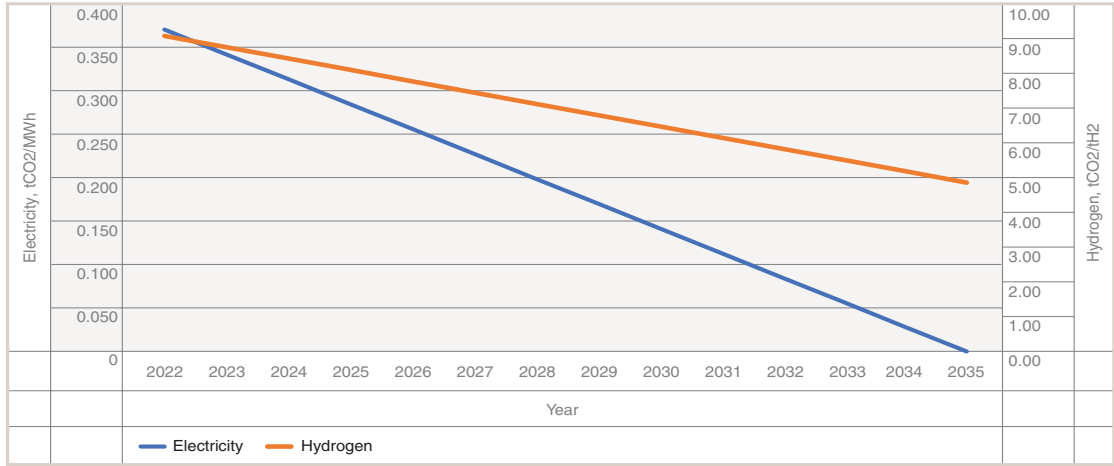
The AESO developed three supply-mix scenarios to assess a future of increased electrification and ambitions to reach net-zero emissions. The AESO’s generation forecast modelling required enhancements to emulate net-zero emissions outcomes by 2035. Specifically, the generation forecast would need to assume more strict emissions policies and enhance the list of available technologies to include a diverse suite of low-emissions generation and energy storage technologies. Each of these areas of analysis is discussed next.

ENHANCEMENTS IN EMISSIONS AND GENERATION FORECAST METHODOLOGIES

Emissions Policy Modelling

The electricity generation modelling used in the AESO Net-Zero Report incorporates key carbon policy assumptions that drive net-zero generation outcomes. The AESO Net-Zero Report assumes that the federally announced \$170-per-tonne carbon price is reached by 2030, with an inflationary increase applied thereafter. The AESO has assumed the continuation of the TIER Regulation in Alberta, but with modified high-performance benchmarks for electricity and hydrogen. The high-performance benchmark for electricity has been modelled as declining, linearly, from 0.37 tCO_{2e}/MWh in 2022 to zero by 2035, while the high-performance benchmark for hydrogen has been modelled as declining, linearly, from 9.068 tCO_{2e}/tH₂ to zero by 2050, resulting in 4.858 tCO_{2e}/tH₂ by 2035.

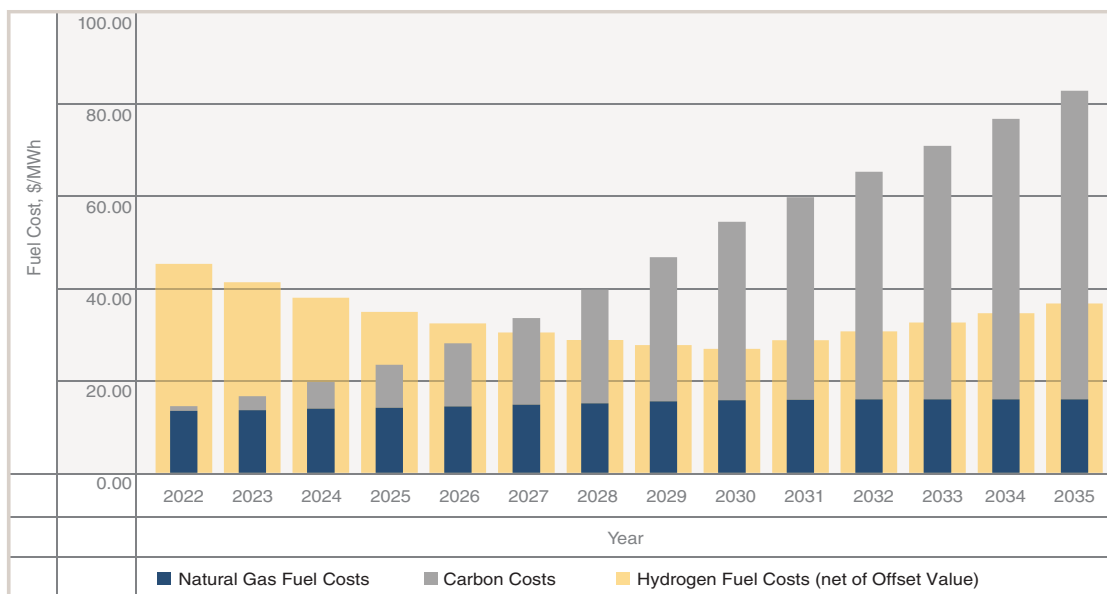
FIGURE 12: Modelled High-Performance Benchmarks for Electricity and Hydrogen



These key carbon policy assumptions create strong disincentives for emissions-intensive technologies via high carbon costs while providing opportunities and cost advantages for low-emissions and zero-emissions generation alternatives.

The modelling of these carbon policy assumptions leads to increased costs for carbon-containing fuels like natural gas, while providing incentives for low-carbon, or carbon-free fuels, like hydrogen. The modelled cost of carbon increases significantly for fossil fuel generators due to two factors: the declining high-performance benchmark for electricity production and the increasing carbon price. Hydrogen fuel costs are modelled to reflect the production cost of blue hydrogen, derived from steam methane reformers, less the value attributed to carbon offsets from the sequestration of CO₂ produced in the process. Blue hydrogen production is a function of the natural gas feedstock price, the capital and operating costs to reform methane, and the cost to compress and sequester carbon dioxide. The regulatory costs under TIER associated with imported hydrogen to power generation facilities are expected to be recovered from the value of sequestration credits, leading to a declining net hydrogen cost until 2030. After 2030, the net hydrogen cost is expected to increase as carbon cost escalation moderates to an inflationary rate, while the high-performance benchmark for hydrogen production decreases at a faster rate. The impact is an increase in net hydrogen costs after 2030. However, by the late 2020s the cost of natural gas fuel for a combined-cycle unit, inclusive of carbon tax, is expected to be higher and to grow through 2035 relative to the cost of hydrogen fuel.

FIGURE 13: Comparative Combined-Cycle Fuel Costs - Natural Gas and Hydrogen (assumed heat-rate of 7.0 GJ/MWh)

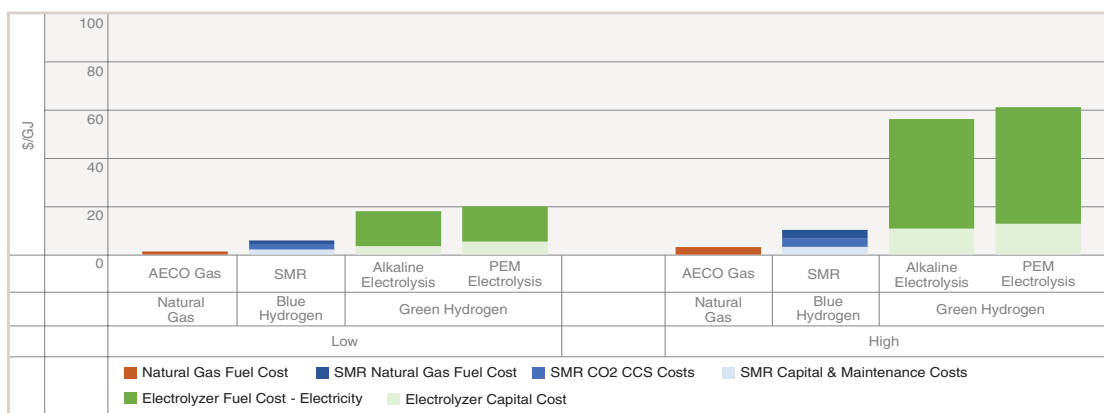


Similarly, carbon pricing impacts the value of combined-cycle generation with CCS. The carbon costs are substantially mitigated by the sequestration of 90 per cent of emissions.

Since blue hydrogen-fired generation and natural gas-fired generation share a common feedstock, methane, both are subject to similar feedstock commodity price risk to their variable electricity generation costs. If the cost of natural gas increases materially, generators could be incented to convert to alternative fuels, such as green hydrogen. The AESO estimates that the total gross cost of blue hydrogen production is between \$8.90 per GJ and \$15.60 per GJ based on an input natural gas fuel cost of \$1.92 per GJ. This cost can be reduced by the value of offsets derived from CO₂ sequestration protocols, estimated to be approximately \$2.21 per GJ when carbon price is \$50-per-tonne. The value of sequestration offsets is expected to increase as carbon price increases, as is the cost associated with fugitive greenhouse gas emissions.

Green hydrogen (hydrogen produced via electrolysis, using zero carbon electricity) was considered as a possible fuel source for the AESO Net-Zero Report analysis. However, currently available electrolysis technologies tend to produce hydrogen at a much higher cost than currently available blue-hydrogen technologies. The AESO estimates that the total cost of green hydrogen production is between \$27.50 per GJ and \$56.40 per GJ, depending on the electrolysis method and the cost of input electricity (modelled as \$50 per MWh in the low case and \$100 per MWh in the high case). The AESO understands that significant research and development is ongoing to develop more efficient and economic methods of clean hydrogen production and expects that new technologies may arise beyond the 2035 timeframe.

FIGURE 14: Combustion Fuel Cost Estimates (without sequestration offset value)



Additional Generation Types for Net-Zero Analysis

In preparation for simulation of net-zero emissions opportunities for generation in Alberta, the AESO reviewed numerous existing and emerging technology types. Many of the technology types represent new asset classes for Alberta’s generation fleet, including nuclear, hydrogen-fired generation, fuel cells, and carbon-sequestration technologies. Other low-carbon supply technologies have a long operational history in Alberta’s electricity sector, including hydroelectric, wind, and solar generation. A diverse suite of these generation technologies was incorporated into the available new resources that the market-economic based generation addition and dispatch model could select simulated resources from. As the AESO continues to review the impacts that a net-zero policy may have on the AIES, emerging technologies will be tracked to help prepare the system for technologies that are advancing due to cost reductions and performance enhancements. The AESO Technology Integration framework will follow emerging trends in the electricity sector to enable the streamlined integration of new technologies.

The AESO’s long-term capacity expansion simulation model selects economic new resources to meet future electricity demand. By enabling the model to select from a wide range of potential zero-emissions and low-emissions technology, the model can optimize simulated generation fleets that can most competitively recover investment costs from the market, minimizing total production costs for the generation fleet within the constraints provided to the model.

Additional Energy Storage Technologies for Net-Zero Analysis

To enhance its modelling of grid-connected asset operations, the AESO has also integrated energy storage technologies into its long-term forecasting efforts. Specifically, the AESO has modelled battery energy storage, compressed-air energy storage, and pumped-hydro energy storage asset types to reflect a diverse set of storage technologies with varied operating characteristics.

Characteristics of Net-Zero Generation Technologies

The AESO Net-Zero Report modelling requires expansion of low-carbon generation technology types. The emergence of carbon pricing, clean electricity standards, and incentives for decarbonized generation technologies changes the comparative costs of generation technologies, providing incentives to decarbonized options while creating challenging economics for carbon-intensive generation technologies. A brief description of the diverse suite of technologies that the AESO has incorporated into the AESO Net-Zero Report follows below and includes their estimated capital costs, operating costs, and operating characteristics.

Importantly, many of the technologies outlined in this report are in early stages of commercialization or adaptation. As such, the cost estimates provided within this report must be considered to have a high degree of uncertainty. Solar photovoltaic (PV) and wind-generation technologies are currently commercially deployed and have well-known operating characteristics. Costs for solar PV, wind, and battery energy storage are anticipated to decline over the coming decades. Significant research and development into these technologies has resulted in recent cost declines, and future potential for economic and technological advancement remains the focus of continued research. Carbon capture technologies, including pre-combustion and post-combustion carbon capture techniques, have been successfully demonstrated and deployed on commercially operating facilities. It is important to note however that worldwide there are very few currently operating commercial electricity generation facilities employing carbon capture, so significant economic and operational uncertainty regarding this technology remains. However, large-scale deployment could result in significant economies of scale. Nuclear technologies have experienced a significant resurgence in research and development of small modular fission reactors that could lead to significant reductions in capital costs, shorter development timelines, and operational performance enhancements. Despite advancements through development, research and commercialization, there is significant risk that the trajectory of technological costs and performance characteristics could deviate from the projections used in the AESO Net-Zero Report. As a result of the uncertainty arising from the unknown relative advancement of low-carbon generation technologies, the AESO has implemented a scenario approach to net-zero emissions electricity modelling, enabling the review of multiple pathways that could change the generation and operational landscape of the electricity market in Alberta.

Nuclear Fission

Nuclear fission involves atomic separation of matter due to the absorption of a neutron. The reaction results in new atoms and a release of significant amounts of thermal energy, which can be harnessed to produce steam and generate power through a Rankine cycle turbine. The technology has been operational for power production since the 1950s, and several enhancements and safety controls have been integrated since that time. Canadian nuclear developments have been stagnant in recent decades, with the last reactor constructed in 1993 in Darlington, Ontario. Alberta does not currently have any commercial nuclear fission reactors supplying its electricity system. Large nuclear fission reactors tend to take a very long time to commercialize. The AESO estimates that it would take at least 10 years to permit, construct, and commission a nuclear facility in the province and therefore achieving net-zero by 2035 using nuclear technology would represent a significant challenge. The AESO has not assessed a detailed capital cost for nuclear fission reactors in the province and instead relies on the U.S. Energy Information Administration (U.S. EIA) estimates for the construction costs (\$6,041 USD per kW), operating costs, and performance characteristics associated with a Westinghouse AP1000.⁵⁴ The technology is assumed to operate in a baseload manner.

⁵⁴ See U.S. Energy Information Administration, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies. February 5, 2020. Pg 28. <https://www.eia.gov/analysis/studies/powerplants/capitalcost/>

Nuclear Small Modular Reactor

Nuclear small modular reactor (SMR) technology represents an advanced commercialization of fission reactors. Small modular reactors are usually defined as 300 MW of capacity per reactor or less. There are currently more than 70 small modular reactor designs, although no dedicated SMR production facility has been established at present. As such, the technology may be too premature to assess a detailed cost estimate in Alberta. Instead, the AESO will rely on construction costs, operating costs, and performance characteristics estimated in the US EIA's 2020 publication, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*. The plant size is estimated to be 600 MW, comprising 12 50-MW SMR units. The capital cost estimate provided in the EIA report, \$6,191 USD per kW, is slightly higher than the large nuclear fission unit capital cost estimate provided by the EIA. With increased interest in SMR technology, cost declines in the technology could be enabled via economies of scale, production efficiency and reduced construction timelines. Although there is increasing interest in nuclear and nuclear-SMR technologies for applications in Alberta, there are currently no nuclear projects in the AESO's Project List (as of June 2022). The relatively high capital cost and large capacity of the units did not result in the economic addition of any nuclear resources in any of the AESO's Net-Zero Report scenarios within the 2022 to 2041 study period.

Hydroelectric

Alberta has numerous rivers that present hydroelectric opportunities. The Peace River, Athabasca River, Slave River, North Saskatchewan River, and South Saskatchewan River cumulatively possess almost 50,000 GWh of annual hydroelectric potential. The majority of the hydroelectric potential in Alberta is in the northern regions of the province, which could complicate construction access and would require significant transmission development. However, hydroelectric development timelines usually take a decade or longer to commercialize, which could challenge their contributions to net-zero ambitions by 2035. Due to high costs in relation to other generation technologies, long development timelines and the capital-intensive nature of hydroelectric developments, the energy-only market framework in Alberta has not resulted in any significant additions of hydro generation capacity, and there are no new hydroelectric dams or run-of-river projects in the AESO's Project List (as of June 2022). Recent capital costs in neighbouring hydro-rich regions have increased to \$14,545 CAD per kW, which represents a significant capital hurdle in Alberta's merchant energy market. For the purposes of the AESO Net-Zero Report modelling, hydroelectric resources were included as a potential resource, but the various generation scenarios did not result in any hydroelectric capacity additions within the 2022 to 2041 study period. The AESO expects that extraordinary government support would be required to develop large-scale hydro capable of achieving net-zero electricity emissions by 2035.

Wind Generation

Wind generation developments in Alberta have a strong history dating back to the 1990s. As wind generation technologies have evolved, their development in Alberta has continued at an increasing pace. Costs for wind generation have declined significantly in the last decade, as turbine sizes have increased and technology has advanced. It is expected that wind generation capital costs will continue to decline through the 2020s. For the purposes of the AESO's net-zero modelling, capital costs of \$1,682 CAD per MWh are expected in 2022, declining to \$1,159 CAD per kW by 2030.

Solar Photovoltaic

Solar photovoltaic (PV) electricity generation in Alberta has become increasingly prevalent in recent years. Large-scale PV installations began to emerge in Alberta in 2017, and developments have accelerated significantly since that time. Capital costs for solar generation are currently estimated at \$1,702 per kW and are expected to decline to \$1,425 per kW by 2030.

Combined-Cycle with Carbon Capture and Sequestration

Natural gas-fired combined-cycle generation can be augmented with carbon emissions control technology to help limit greenhouse gas emissions. Although combined-cycle with CCS technology is currently in a very early operational state, the power generation and emissions-control technologies themselves are well understood and advanced. Combined-cycle units with CCS facilities are expected to operate in a base-load configuration, since amine-based carbon capture technologies require relatively constant temperature and flow rates to effectively remove carbon dioxide from flue gas. Carbon capture and sequestration technology is expected to capture and store 90 per cent of the CO₂ produced by the combustion of natural gas in the turbine, enabling low-carbon base-load generation. The parasitic load requirements of the carbon capture equipment are expected to reduce gross plant capacity by 20 MW and the total plant auxiliary load is 31.7 MW. Steam for CO₂ stripping would reduce the output of the Rankine cycle by 21 MW, resulting in a net capacity of 377 MW. Comparatively, a similar combined-cycle natural gas facility without CCS would produce 430.4 MW. The net heat-rate for the reference facility is expected to be 7.52 GJ/MWh.

Hydrogen-Fired Combustion Technologies

Hydrogen-fired combustion technologies are under development by many major gas turbine and engine suppliers. Hydrogen-fired technology can be deployed in simple-cycle and combined-cycle configurations. Conventional gas turbines will need to be modified and optimized to burn 100 per cent hydrogen gas rather than hydrocarbons. For the purposes of the AESO's Net-Zero Pathways Analysis, the source hydrogen was assumed to be derived from blue hydrogen sources, as they are expected to be the least expensive low-carbon hydrogen source for the near term. The blue hydrogen production technology modelled was steam methane reforming, paired with carbon capture and storage. The AESO has modelled hydrogen fuel cost as though fuel is purchased in an arm's length transaction from a producer utilizing the steam methane reforming process. As such, the fuel cost for hydrogen includes the producer's return-on and return-of capital for the steam methane reforming facility, but also the natural gas feedstock required to produce the hydrogen. The value of the carbon offsets derived from sequestration of carbon dioxide flue gas through steam methane reforming is expected to reduce the arm's-length cost of blue hydrogen. Hydrogen-fired generation options included in the AESO's Net-Zero Report include aeroderivative simple-cycle turbines, frame simple-cycle turbines, and one-on-one combined-cycle power stations.

Energy Storage

Energy storage technologies included in the AESO's Net-Zero Report are pumped-hydro, compressed-air, and battery technologies. Each of these technologies has unique attributes including the round-trip efficiency, capital costs, useful life, operating costs, and storage durations, providing a diverse suite of storage options.

Battery Energy Storage

The AESO has modelled lithium-ion battery energy storage technology with a four-hour storage capacity. However, the technology can be configured for longer or shorter storage durations and can be scaled to meet diverse energy storage applications. The battery technology simulated in this analysis has a 10 MW power capacity, and 40 MWh energy storage capacity (four-hour duration). Capital and operating cost estimates and operating characteristics were derived from the Pacific Northwest National Laboratory report, *2020 Grid Energy Storage Technology Cost and Performance Assessment (PNNL Report)*.⁵⁵ The round-trip efficiency is expected to increase modestly, from 86 per cent in 2020 to 88 per cent in 2030, and costs are expected to decline from \$2,244 per kW to \$1,603 per kW in the same timeframe. Significant research and development of chemical-battery storage technologies could lead to alternative battery technologies, advanced performance, and decreased costs in the future.

Compressed-Air Energy Storage

Compressed-air energy storage was modelled as a long-duration asset with a 60-hour duration. The reference facility was modelled as a 100 MW power capacity and a 6,000 MWh energy capacity. The round-trip efficiency of compressed-air energy storage has been estimated as 52 per cent. Capital costs for compressed-air energy storage technologies were derived from the PNNL Report, and are represented as \$1,585 per kW in this analysis.

Pumped-Hydro Energy Storage

The AESO has modelled pumped-hydro energy storage as a long-term 19-hour energy storage technology, with a 150 MW power capacity and a 2,850 MWh energy capacity. The estimated round-trip efficiency of pumped hydro storage is 80 per cent. Capital costs for pumped-hydro energy storage technologies were derived from the PNNL Report, and are represented as \$3,493 per kW in this analysis.

Technological Assumptions and Operating Characteristics

The emerging technologies utilized in the AESO's Net-Zero Pathways Analysis incorporate a broad selection of generation options characterized by capital costs, operating costs, and unique performance traits. To the extent possible, these characteristics were derived from publicly available sources and converted to Canadian dollars, when applicable. Some of the generation technologies are mature in their development—for example, wind, solar PV, hydroelectric, and nuclear fission—and may have a relatively strong cost basis. Others, like hydrogen-fired generation and combined-cycle with CCS, may be represented by less certain cost and performance characteristics, which may deviate from publicly available estimates. Table 1, below outlines key cost and capacity characteristic assumptions utilized for the technologies considered in the AESO's Net-Zero Report. The AESO expects that these estimates may be subject to volatility and deviations due to material and labour cost changes, regional price differences, technological refinements, and project specific costs.

⁵⁵ Pacific Northwest National Laboratory Report available at the following URL: <https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf>

TABLE 1: Characteristics of Low-Carbon Electricity Technologies Modelled in the AESO's Net-Zero Pathways Analysis

Technology	Capacity, MW	Capital Cost, \$2022/kW		Efficiency or Heat-Rate, % or GJ/MWh	Fixed O&M, \$2022/kW-yr		Variable O&M, \$2022/MWh
		2022	2026				
Solar PV – 2022; 2026	50	1,702	1,425	-	35		-
Wind – 2022, 2026	50	1,682	1,159	-	35	32	-
Nuclear Fission	2,156	8206		-	165		3.22
Nuclear Fission SMR	600	8410		-	129		4.08
Hydroelectric	100	14,545		-	41		-
Combined-Cycle CCS	377	3,370		7.52 GJ/MWh	37		7.93
Hydrogen-Fired Combined-Cycle	418	1841		6.79 GJ/MWh	55		2.75
Hydrogen-Fired Simple-Cycle – Frame	233	992		10.45 GJ/MWh	30		0.82
Hydrogen-Fired Simple-Cycle – Aeroderivative	105	1,280		9.68 GJ/MWh	58		4.69
Battery Energy Storage	10 (4 hour)	2244	1603	86% to 88%	5		0.68
Compressed-Air Energy Storage	100 (60 hour)	1585	1577	52%	21		0.68
Pumped-Hydro Energy Storage	150 (19 hour)	3493		80%	40		0.68

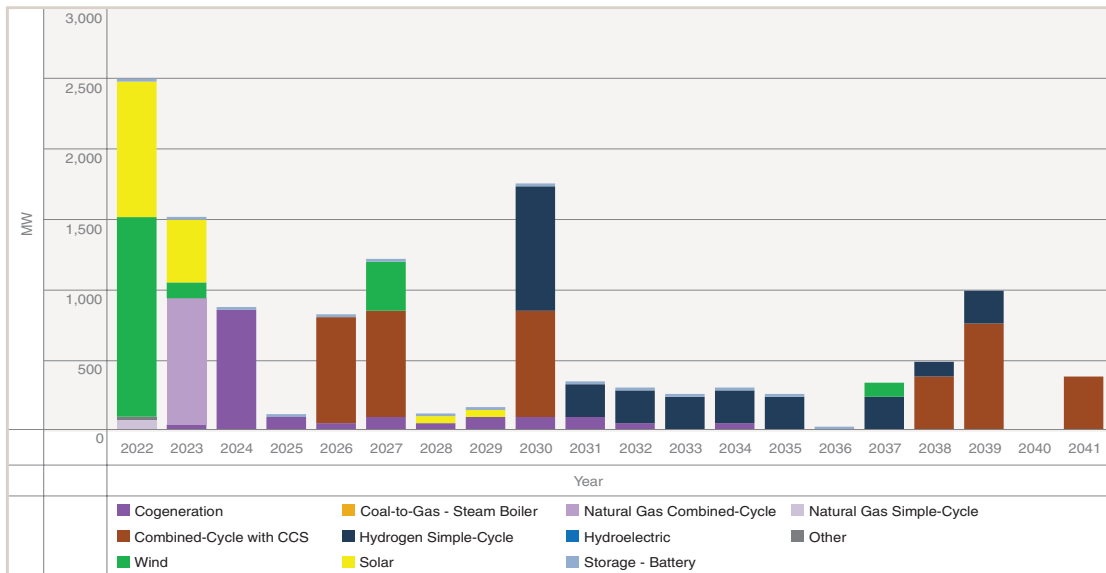
GENERATION FORECASTS

Utilizing the demand forecast, supply operating and cost characteristics and other assumptions described above, the AESO's economic expansion and dispatch cost modelling produced the following results on a scenario-by-scenario basis.

Dispatchable Dominant Scenario

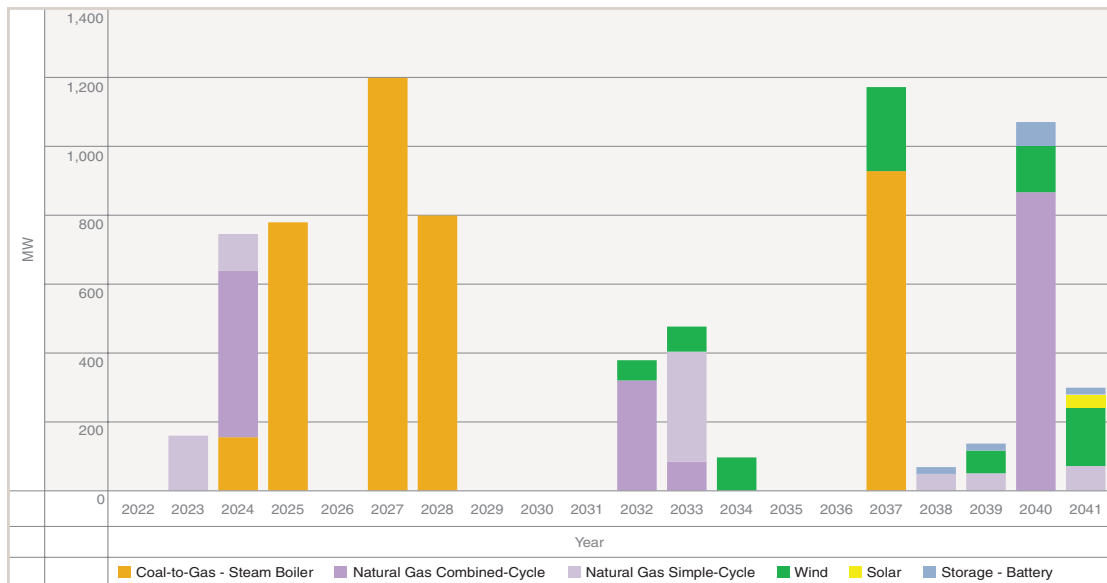
Capacity Additions and Retirements

FIGURE 15: Dispatchable Dominant Scenario - Capacity Additions



The Dispatchable Dominant Scenario results in over 12,300 MW of capacity additions between 2022 and 2041. Most of these additions are combined-cycle with CCS generation (3,770 MW) and hydrogen-fired simple-cycle generation (2,622 MW). Renewables additions include 1,982 MW of additional wind capacity, and 1,509 MW of solar, predominantly in the near term. In 2023, a 900-MW natural gas combined-cycle facility is commissioned and in 2024, an 800-MW cogeneration facility enters service. In this scenario, 300 MW of battery energy storage is added, incrementally, by 2036.

FIGURE 16: Dispatchable Dominant Scenario - Capacity Retirements

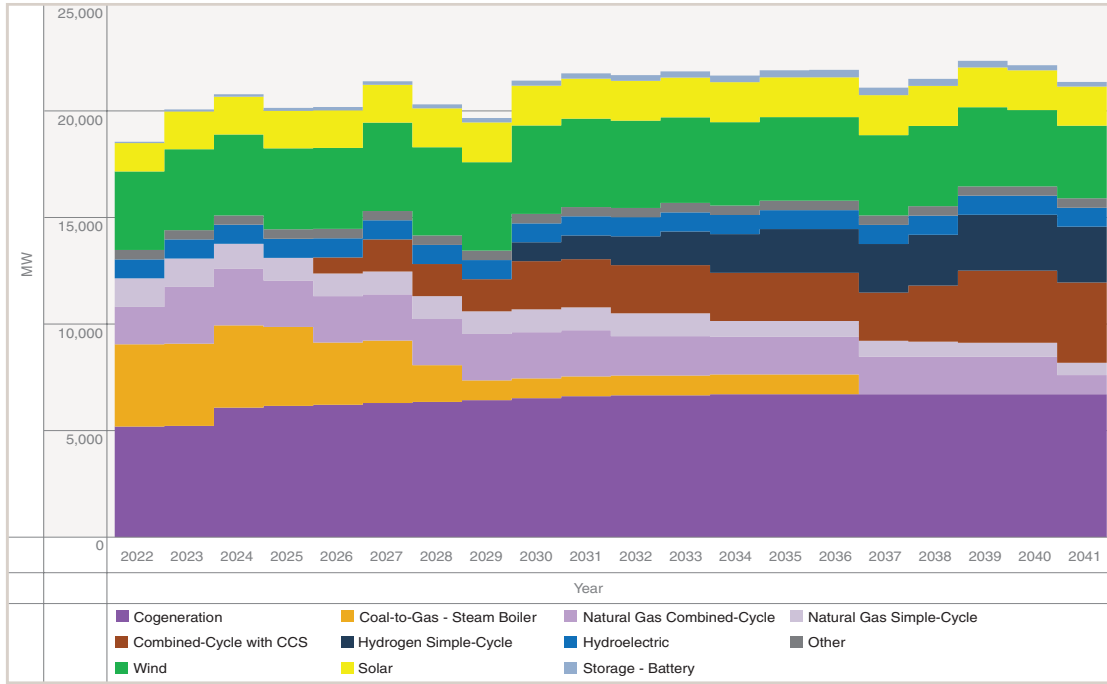


Generation facility retirements in the AESO's Net-Zero Report Analysis are driven by the go-forward economics of individual generating facilities. Generally, higher emitting technologies become less economic as carbon prices increase and new, lower emissions technologies develop. The capacity factors at higher emitting units decline as carbon prices increase and lead to reduced margins for these units. Eventually, the go-forward fixed costs of the units cannot be offset by operating margins and the units retire.

The Dispatchable Dominant Scenario forecasts the retirement of emissions-intensive coal-to-gas conversion units by 2037. The scenario also expects significant simple-cycle and combined-cycle natural gas retirements throughout the forecast horizon. Renewables retirements occur at the end of useful life for various facilities through the 2030s. However, assets may retire later if there are economic or reliability reasons to do so (i.e., new generation is delayed).

Total Capacity

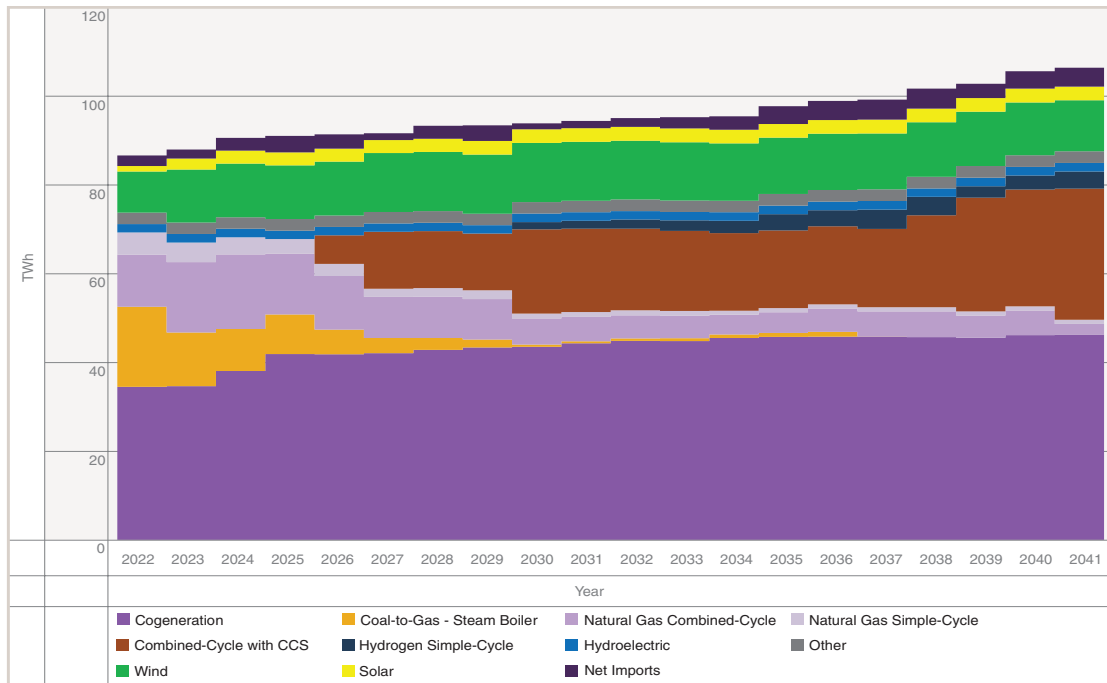
FIGURE 17: Dispatchable Dominant Scenario - Total Capacity



Combined-cycle generation with CCS and hydrogen-fired simple-cycle generation comprise most of the supply additions in the Dispatchable Dominant Scenario. Renewables capacity remains relatively consistent throughout the forecast horizon in this scenario. The major transition in capacity is due to a reduction in higher emissions natural gas-fired capacity, such as coal-to-gas converted units, and an increase in low-emissions capacity, such as combined-cycle with CCS and hydrogen-fired capacity.

Total Generation

FIGURE 18: Dispatchable Dominant Scenario - Total Generation



The Dispatchable Dominant Scenario demonstrates a significant shift away from natural gas generation (combined-cycle, simple-cycle, and coal-to-gas conversion units) to combined-cycle with CCS and hydrogen-fired generation. Wind, solar, and hydroelectric generation provide sustained contributions to the clean-energy grid throughout the forecast term. As with other scenarios, cogeneration continues to provide significant contributions to the total energy consumed in Alberta. Fossil-fuel-based combined-cycle and simple-cycle generation diminished significantly throughout the forecast horizon. By 2030, 23 per cent of the energy generated in Alberta is forecast to come from renewable resources in the Dispatchable Dominant Scenario.

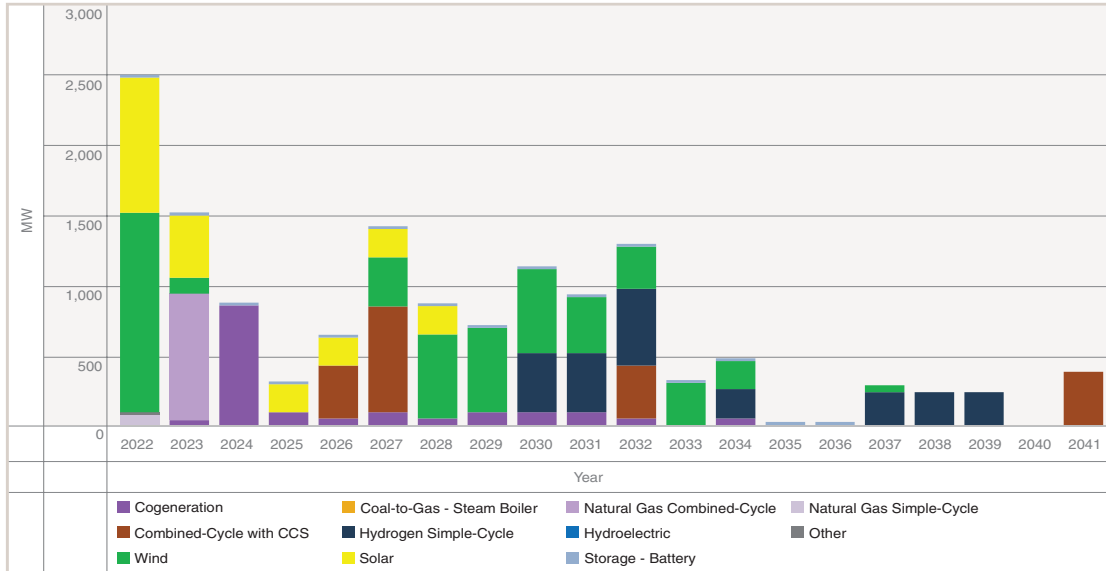
TABLE 2: Renewables Penetration for Dispatchable Dominant Scenario

Percentage of Total Domestic Generation produced by Renewables				Percentage of System Load Forecast (estimated as 70% of AIL forecast) served by Renewables			
2022	2030	2035	2041	2022	2030	2035	2041
18%	23%	24%	22%	25%	33%	34%	31%

First-Mover Advantage Scenario

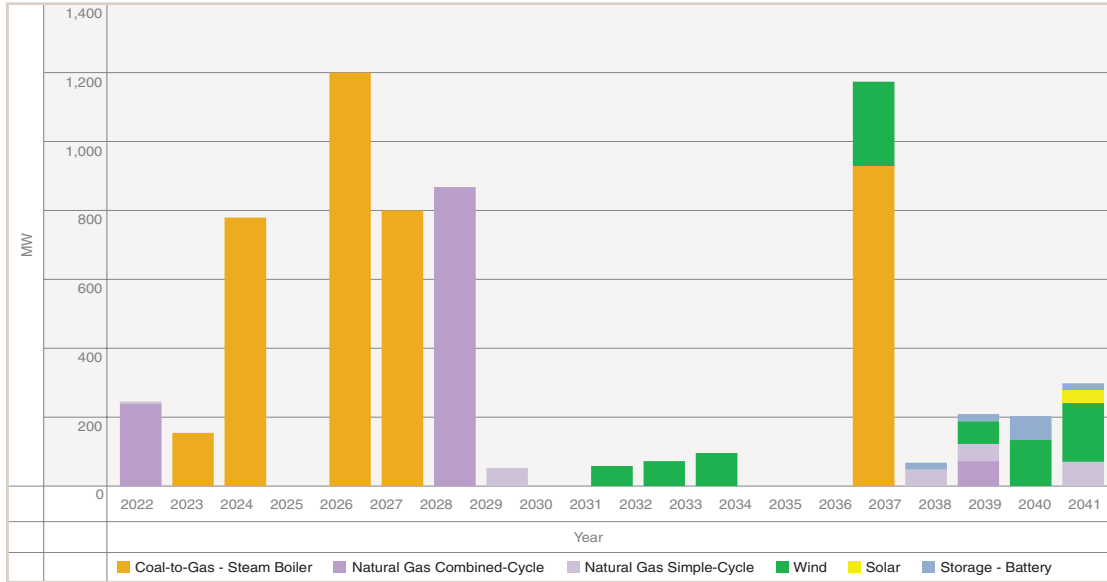
Capacity Additions and Retirements

FIGURE 19: First-Mover Advantage Scenario - Capacity Additions



The First-Mover Advantage Scenario demonstrates a decarbonization transition that adds significant renewables electricity capacity. In this scenario, 4,932 MW of wind-generating capacity and 2,209 MW of large solar-generating capacity (greater than 5 MW projects) are developed between 2022 and 2041. This scenario relies on the development of 1,885 MW of combined-cycle with CCS and 2,297 MW of hydrogen-fired simple-cycle generation to balance energy needs. Cogeneration and traditional natural gas-fired generation builds are identical to the Dispatchable Dominant and Renewables and Storage Rush scenarios in the early part of the time horizon, as these units have achieved the AESO's project certainty criteria. This scenario includes 300 MW (1,200 MWh) of additional lithium-ion battery energy storage capacity.

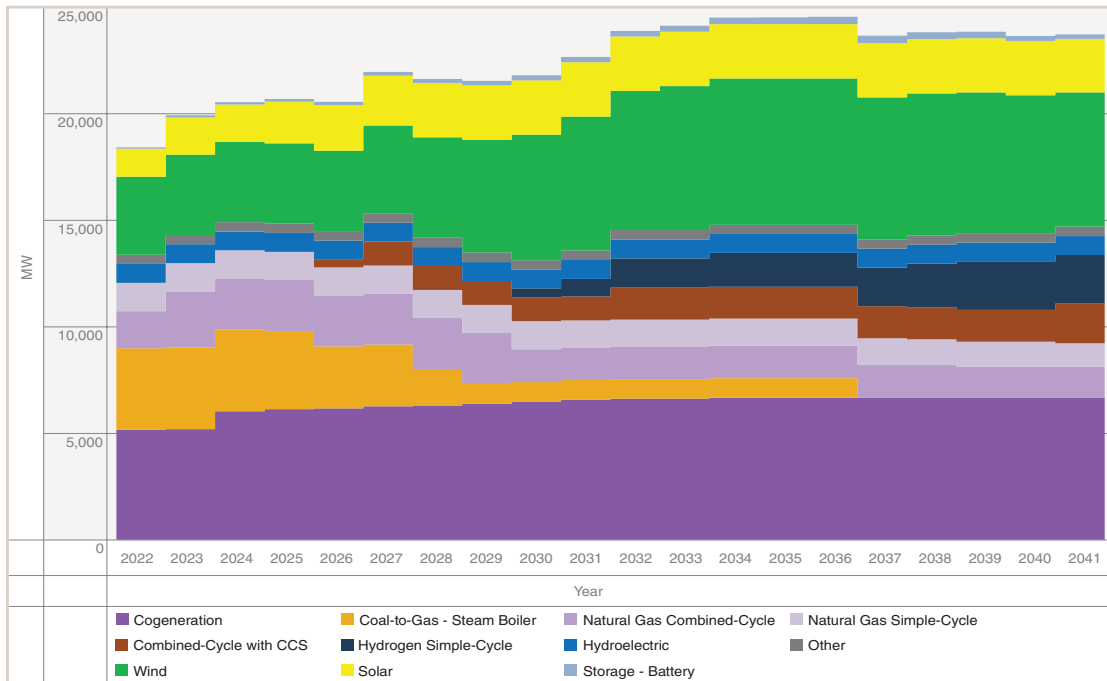
FIGURE 20: First-Mover Advantage Scenario - Capacity Retirements



Retirements in the First-Mover Advantage Scenario include all legacy-converted coal units, numerous simple-cycle and combined-cycle natural gas-fired units. A modest amount of renewables-generating facility retirements are forecast through the 2030s as older generating facilities reach the end of their useful lives.

Total Capacity

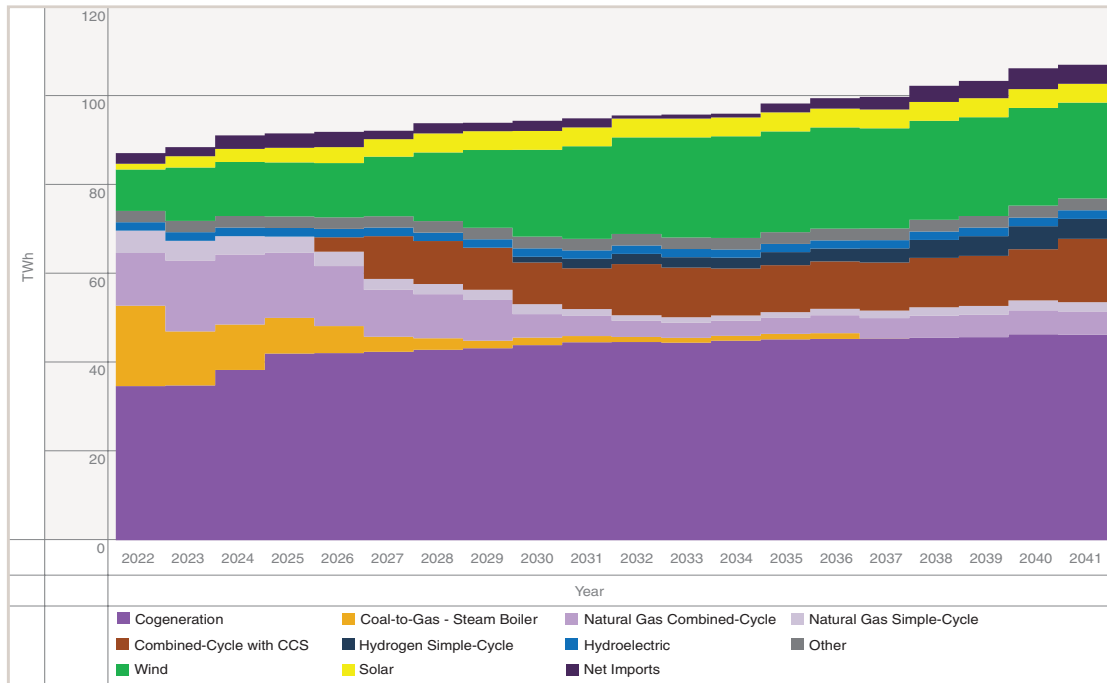
FIGURE 21: First-Mover Advantage Scenario - Total Capacity



Wind and solar experience significant growth through 2035 in the First-Mover Advantage Scenario. This scenario also projects significant growth in combined-cycle with CCS and hydrogen-fired simple-cycle generation. Energy storage makes up a modest component of the capacity in this scenario, expected to provide specific energy services to the grid.

Total Generation

FIGURE 22: First-Mover Advantage Scenario - Total Generation



Wind and solar generation contribute meaningfully to the growth in generation in the First-Mover Advantage Scenario. Approximately 32 per cent of the generation in Alberta is expected to come from renewable resources by 2030 in this scenario, increasing to 35 per cent by 2035. Growth in low-emissions combined-cycle with CCS technology and hydrogen-fired simple-cycle generation largely offset the decline in natural gas-fired combined-cycle and simple-cycle generation into the 2030s. As with other scenarios, cogeneration continues to supply a significant portion of the electrical demand in Alberta.

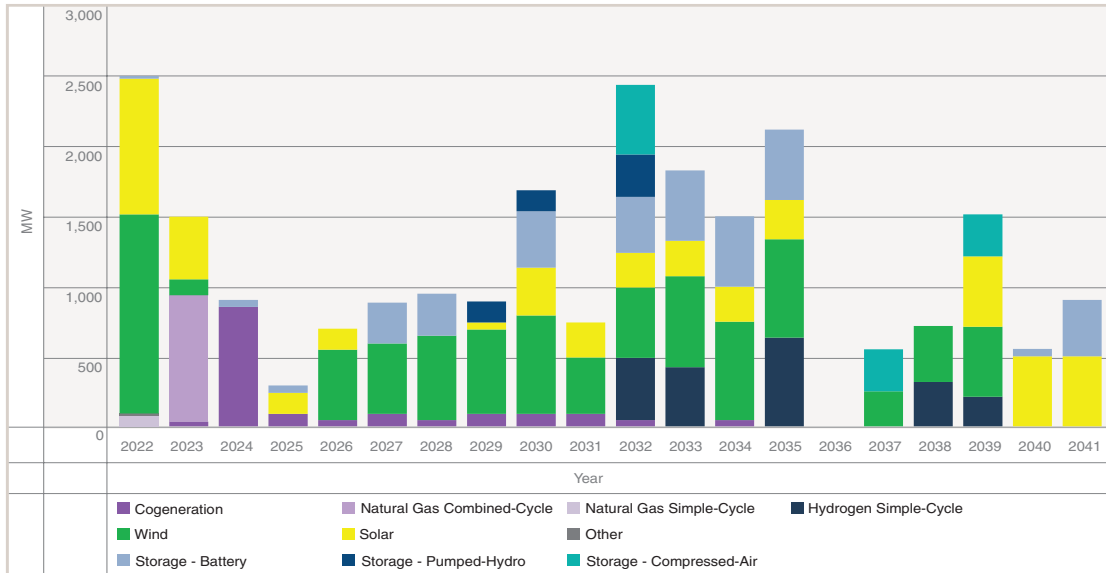
TABLE 3: Renewables Penetration for First-Mover Advantage Scenario

Percentage of Total Domestic Generation produced by Renewables				Percentage of System Load Forecast (estimated as 70% of AIL forecast) served by Renewables			
2022	2030	2035	2041	2022	2030	2035	2041
18%	32%	35%	32%	25%	44%	50%	46%

Renewables and Storage Rush Scenario

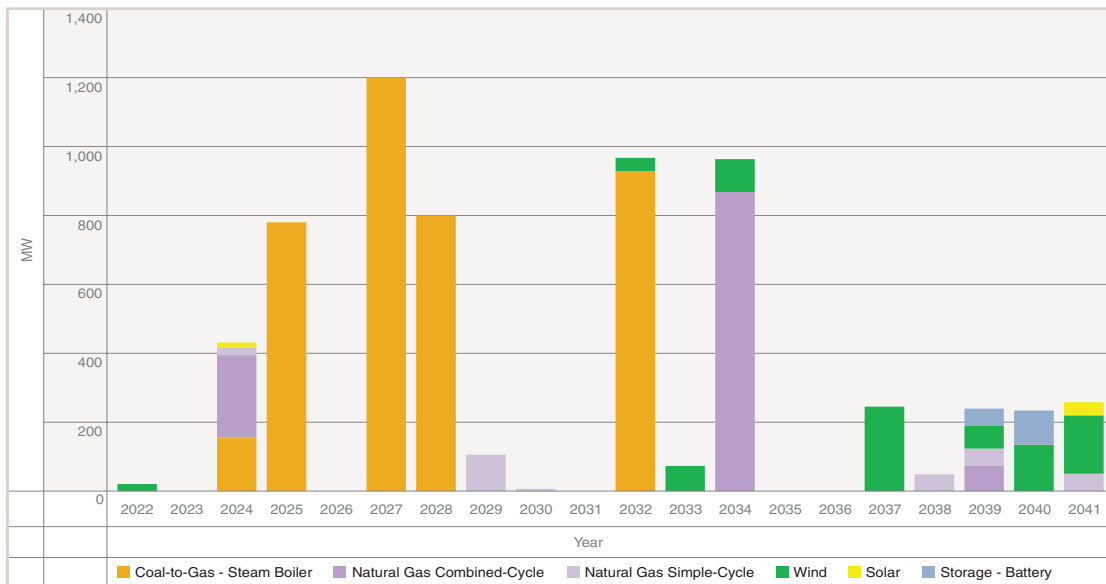
Capacity Additions and Retirements

FIGURE 23: Renewables and Storage Rush Scenario - Capacity Additions



The Renewables and Storage Rush Scenario results in the largest capacity build. The scenario incorporates the development of 5,157 MW of storage capacity, including 600 MW of pumped-hydro storage, including 1,096 MW of compressed-air energy storage, and 3,461 MW of battery energy storage.

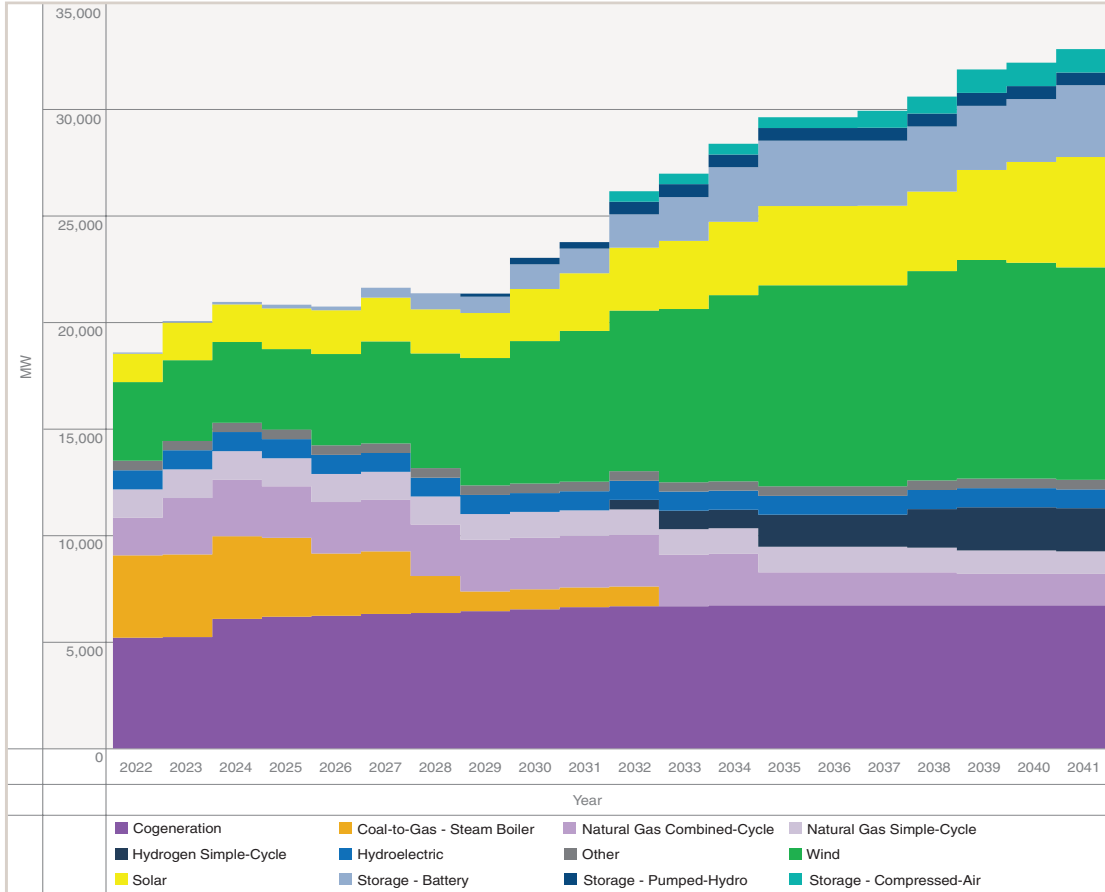
FIGURE 24: Renewables and Storage Rush Scenario - Capacity Retirements



Retirements in the Renewables and Storage Scenario consist of all coal-to-gas converted units, some simple-cycle and combined-cycle facilities, and some renewables generation facilities that reach their end of useful life.

Total Capacity

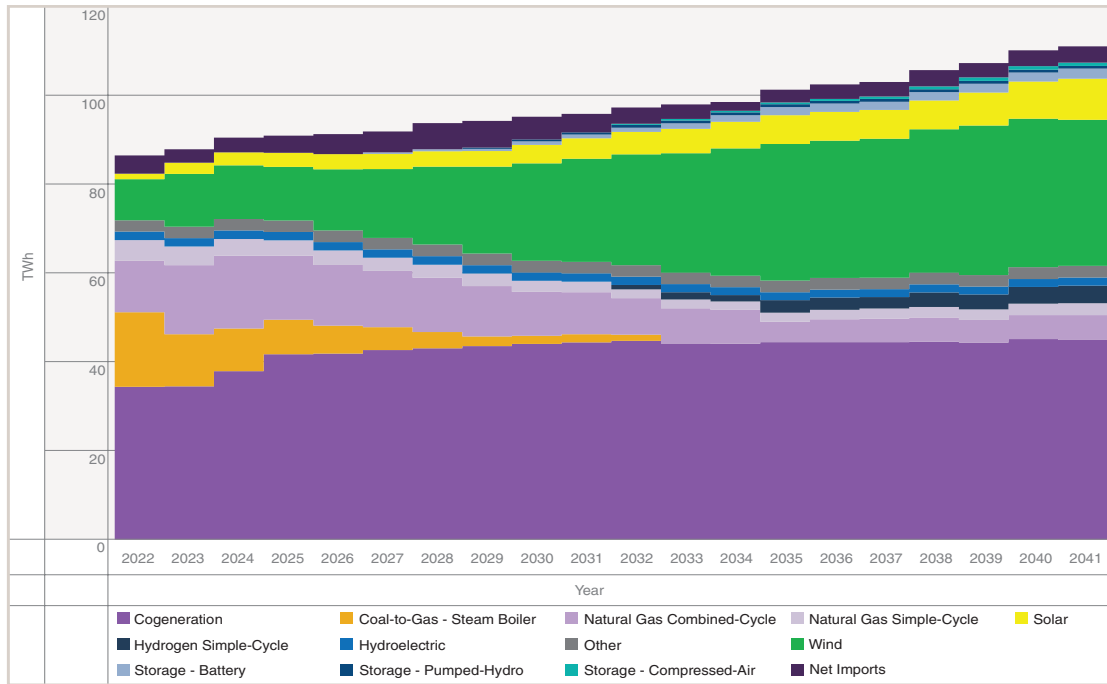
FIGURE 25: Renewables and Storage Rush Scenario - Total Capacity



The Renewables and Storage Rush Scenario adds the largest amount of renewables generation capacity in the AESO Net-Zero Report. In this scenario, wind capacity overtakes cogeneration capacity by 2030 and continues to grow to 9,957 MW at the end of the forecast period. Solar PV capacity increases to over 5,186 MW by the end of the forecast period. Storage capacity grows significantly through the 2030s to 5,058 MW in 2041. In this scenario, 2,019 MW of hydrogen-fired simple cycle generation assist with grid balancing energy.

Total Generation

FIGURE 26: Renewables and Storage Rush Scenario - Total Generation



Wind and solar growth contribute meaningfully to Alberta’s forecast electricity generation in the Renewables and Storage Rush Scenario. Thirty-five per cent of the forecast energy generation comes from renewables by 2030, and by 2035 renewable energy generation accounts for 46 per cent of generated electricity. As with other scenarios, cogeneration continues to provide the largest source of electricity generation on the AIES in the Renewables and Storage Rush Scenario. Remaining combined-cycle and simple-cycle natural gas-fired generation, and simple-cycle hydrogen-fired generation cumulatively account for less than 15 per cent of the total energy requirements of the AIES beyond 2030, acting as a balancing solution in times of renewables and storage scarcity.

TABLE 4: Renewables Penetration for Renewables and Storage Rush Scenario

Percentage of Total Domestic Generation produced by Renewables				Percentage of System Load Forecast (estimated as 70% of AIL forecast) served by Renewables			
2022	2030	2035	2041	2022	2030	2035	2041
18%	35%	46%	47%	25%	49%	66%	68%

TABLE 5: Comparison of Net-Zero Emissions Pathways Scenarios and 2021 LTO

Description	Dispatchable Dominant	First-Mover Advantage	Renewables and Storage Rush	2021 LTO Clean-Tech	2021 LTO Ref Case
	2035	2035	2035	2035	2035
	Equal and Greater than 5 MW Generation (MW Installed Capacity)				
Wind	3,922	6,922	9,422	4,997	4,747
Solar	1,872	2,572	3,724	2,539	1,189
Storage - Battery	330	330	3,060	1,020	85
Storage - Compressed Air	-	-	496	-	-
Storage - Pumped Hydro	-	-	600	75	-
Hydrogen Simple Cycle	2,049	1,599	1,494	-	-
Combined-Cycle with CCS	2,262	1,508	-	-	-
Natural Gas Combined-Cycle	1,768	1,548	1,548	4,822	2,648
Natural Gas Simple-Cycle	751	1,278	1,205	1,544	1,397
Coal-to-Gas - Steam Boiler	929	929	-	935	2,535
Cogeneration	6,712	6,712	6,712	6,669	6,669
Hydroelectric	894	894	894	894	894
Other	443	443	443	483	423
Total	21,932	24,735	29,598	23,978	20,587
	Less than 5 MW Generation (MW Installed Capacity)				
Solar	2,074	2,074	2,074	1,780	638
Wind	45	45	45	52	44
Gas	158	158	158	174	138
	Load Forecast (After Factoring Energy of Less than 5 MW Generation)				
Peak AIL (MW)	14,245	14,245	14,245	13,660	12,949
Average AIL (aMW)	11,162	11,162	11,162	10,421	10,560

Emissions Reduction Outcomes



EMISSIONS CALCULATION METHODOLOGY

The AESO's Net-Zero Pathways Analysis focuses on emissions outcomes from potential electricity grid future energy supply mixes. The diverse nature of the Alberta electricity system's generation supply introduces complexity in the calculation of emissions. Many facilities in Alberta generate electricity on site as part of their manufacturing production, refining, and resource extraction activities. The integrated nature of these facilities may lead to the export of excess electricity to the AIES and may also introduce multiple sources of greenhouse gas emissions from a single facility. Greenhouse gas records collected by the Government of Canada in the Greenhouse Gas Reporting Program (GHGRP) – Facility Greenhouse Gas (GHG) Data⁵⁶ provide detailed insights into sectoral emissions, categorized by North American Industry Classification System codes (NAICS codes).

Based on available data, accurately differentiating between emissions attributed to electricity production and those attributed to other industrial activities becomes difficult. Cogeneration—the simultaneous production of electricity and other useful products—further complicates the calculation of emissions from integrated facilities: A single cogeneration unit may produce useful process heat and electricity, as well as greenhouse gas by-products which are single-source emissions related to the creation of multiple products.

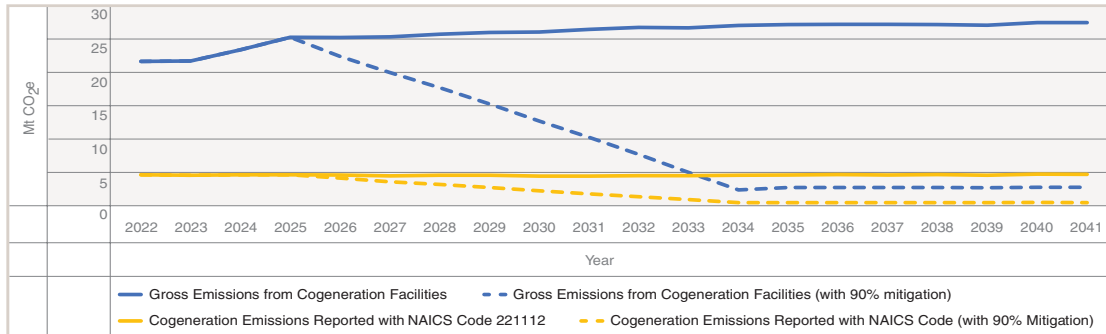
The AESO's calculation of emissions follows the methodology of greenhouse gas emissions reported to the Government of Canada's GHGRP in Alberta, associated with the following NAICS codes:

- 221112 - Fossil-fuel electric power generation
- 221111 - Hydro-electric power generation
- 221119 - Other electric power generation

There are approximately 1,000 MW of cogeneration facilities, out of 5,197 MW of existing capacity, that report their greenhouse gas emissions using the NAICS codes 221112. Such facilities are included in the emissions calculations performed by the AESO. This methodology enables accurate comparison of greenhouse gas emissions forecasts with historical data collected by the Government of Canada.

⁵⁶ <https://open.canada.ca/data/en/dataset/a8ba14b7-7f23-462a-bdbb-83b0ef629823/resource/ea4be66b-b7fa-46dc-af7c-5a1a460eaafd>

FIGURE 27: Cogeneration Emissions



Cogeneration facilities in Alberta service the oil and gas sector, chemical production sector, pulp and paper industry and various other economic sectors. These facilities typically report greenhouse gas emissions in their primary product categories. The AESO anticipates that governments will take an economy-wide approach to emissions reductions, and that similar greenhouse gas targets will be implemented in sectors other than electric power generation to achieve reduction objectives. It is therefore plausible that pre-combustion and post-combustion carbon sequestration methods will be able to reduce carbon dioxide emissions from cogeneration facilities by 90 per cent.

To the extent that the AESO’s scenario emissions forecasts contain physical emissions, the AESO has assumed that remaining emissions may need to use carbon offsets, emissions performance credits, or other regulatory mechanisms that enable net-zero emissions outcomes. However, the AESO also expects that owners of the remaining emitting facilities will explore alternatives to mitigate compliance costs, including CCS retrofits, hydrogen firing or co-firing, and efficiency upgrades. The AESO has not included the estimation of these retrofit alternatives in its cost or emissions forecast due to the complex and unique nature of individual facility constraints and opportunities. Instead, the AESO has estimated the cost of offsets or emissions performance credits, assuming a 15 per cent discount to the price of carbon.

ADDITIONAL OPPORTUNITIES FOR EMISSION REDUCTIONS

In addition to new generation facilities, emissions-reduction techniques could be applied as retrofits to existing facilities. Although the economics of such decisions will be unique to each facility, it is feasible that existing natural gas-fired generation facilities could modify facility hardware and convert to alternative fuels such as hydrogen or renewable natural gas. Alternatively, existing generation facilities could retrofit post-combustion CCS emissions control technologies. Either of these approaches could further reduce the physical emissions outcomes described in the scenarios below.

Other sectors beyond the electricity sector also face decarbonization objectives, often with different timelines but with the opportunity to integrate similar emissions-control technologies. It is expected that existing cogeneration and oil production facilities could implement physical reduction techniques such as hydrogen fuel-switching, renewable natural gas fuel-switching, and post-combustion CCS to mitigate emissions from cogeneration and oil production facilities. CCS has been described as a step in the Oil Sands Pathways to Net Zero initiative.⁵⁷ In the AESO’s emissions assessments, it is assumed that 90 per cent of cogeneration emissions would be abated via some combination of these emissions reduction technologies, leading to reductions in cogeneration emissions attributed to several industries, including electricity generation.

⁵⁷ <https://pathwaysalliance.ca/our-plan/#getting-started>

Post-combustion carbon capture techniques could increase on-site electrical load, compared to a status-quo scenario, thereby reducing the net export of electricity from BTF cogeneration systems. The AESO estimates that integration of post-combustion carbon capture at cogeneration facilities could increase the net system load (or reduce export supply) by 252-504 MW by 2035, depending on the pace of CCS adoption, as shown above in Figure 10.

Alternatively, electrification of steam generation, currently supplied by gas-turbine-based cogeneration facilities, could reduce the available net export of electricity from industrial sites, leading to a significantly increased need for generation capacity on the AIES. Changes to the regulatory treatment of cogeneration system emissions could significantly alter Alberta’s electricity generation landscape, but the TIER Regulation treatment of cogeneration incentivizes highly efficient conversion of fuel into useful heat and electricity.

Each facility owner will need to weigh the capital and operating costs associated with emissions reductions approaches that best fit their business model. Factors could include emissions pricing, regulatory framework, retrofit costs, government incentives, remaining facility useful life, and investment objectives.

OFFSETS AND CREDITS ENABLING NET-ZERO

Alberta’s TIER Regulation allows emitters to comply with emissions reductions requirements using three mechanisms: emissions offsets, emissions performance credits, and fund credits. Emissions offsets and emissions performance credits are tradeable mechanisms that represent one tonne of carbon dioxide-equivalent emissions, whereas fund credits are obtained via payment to the TIER Fund. Generally, a facility can meet its compliance requirements by sourcing a combined maximum of 60 per cent of the true-up obligation using emissions offsets and emissions performance credits.

EMISSIONS RESULTS

The AESO’s net-zero scenarios lead to physical emissions levels that are substantially reduced from historical levels, and represent further physical reductions from the levels exhibited in the AESO’s 2021 LTO Reference Case forecast.

TABLE 6: 2035 Forecast Physical Greenhouse Gas Emissions by Scenario

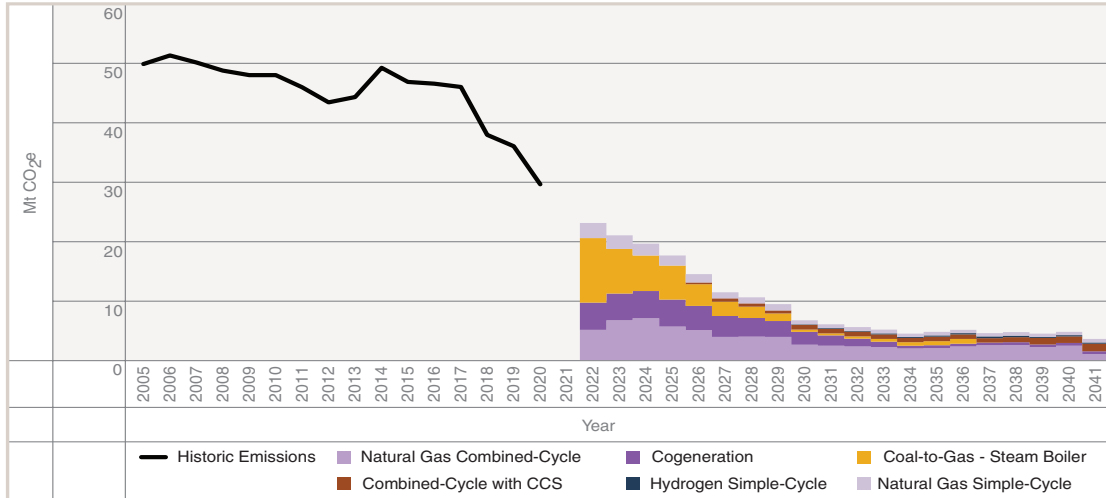
2035 Forecast Physical Greenhouse-Gas Emissions by Scenario	
2021 LTO Reference Case ⁵⁸	17.7 Mt
Dispatchable Dominant Scenario	4.8 Mt
First-Mover Advantage Scenario	4.3 Mt
Renewables and Storage Rush Scenario	3.8 Mt

“Of the scenarios modelled, each indicates a level of residual physical emissions. To achieve net-zero emissions by 2035, the application of offsets and credits is likely required, as physical abatement down to zero emissions is unlikely given both cost and operational considerations.

⁵⁸ The annual emission estimates from the 2021 Long-term Outlook can be found in the Data File available at <https://www.aeso.ca/grid/forecasting/>

Dispatchable Dominant Scenario Emissions Results

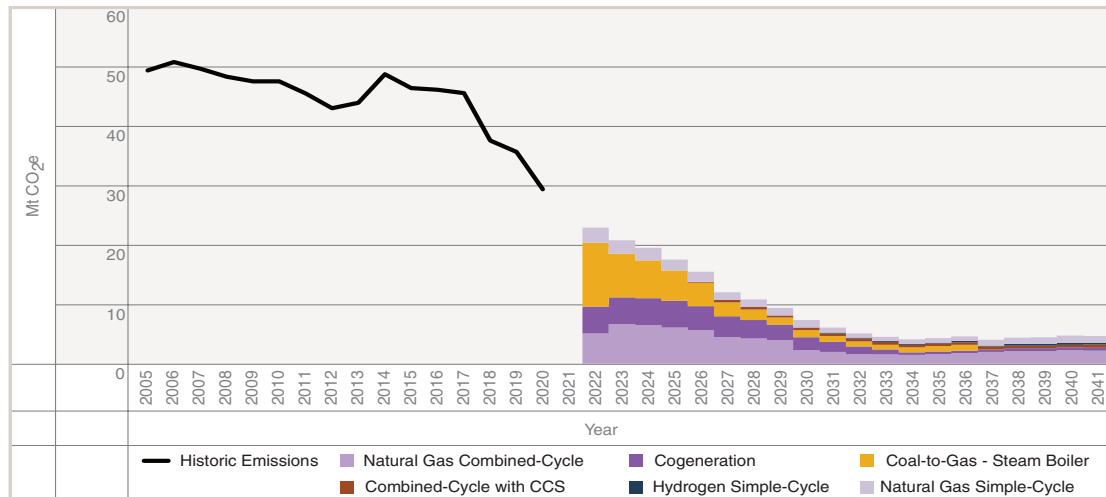
FIGURE 28: Dispatchable Dominant Scenario - Total Electricity Sector Greenhouse Gas Emissions



The Dispatchable Dominant Scenario contains many carbon capture facilities associated with hydrogen production and post-combustion carbon capture. The amine absorption processes are expected to capture 90 per cent of the CO₂ contained in the flue gas that can then be sequestered, resulting in significant emission reductions. However, the remaining CO₂ is expected to be released into the atmosphere, resulting in emissions associated with generation technologies utilizing CCS. By 2035, the remaining electricity sector greenhouse gas emissions are expected to be 4.8 megatonnes in this scenario. Such emissions could be mitigated by using offsets and EPCs, leading to a net-zero emissions outcome. Emissions from existing natural gas-fired generation sources could be reduced, though likely not completely eliminated, by retrofits of post-combustion carbon capture, fuel switching, or blending with hydrogen or renewable natural gas.

First-Mover Advantage Scenario Emissions Results

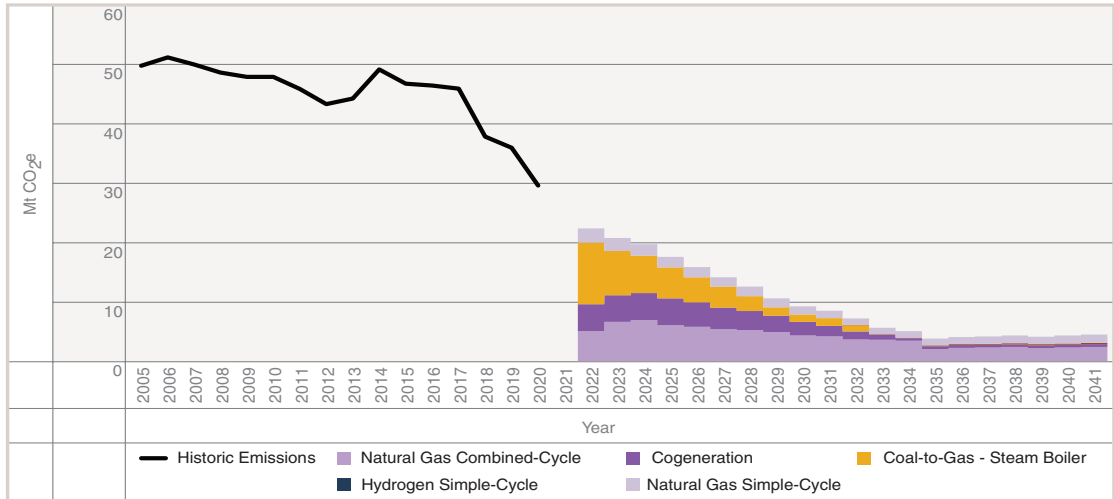
FIGURE 29: First-Mover Advantage Scenario - Total Electricity Sector Greenhouse Gas Emissions



Despite the significant increase in renewables generation in the First-Mover Advantage Scenario, some dispatchable generation is still required to provide resource adequacy. The emissions associated with this scenario are expected to be 4.3 megatonnes in 2035. As with the Dispatchable Dominant Scenario, it is expected that a combination of fuel switching, low-carbon fuel blending, post-combustion carbon capture, and application of offsets and EPCs can result in a net-zero emissions outcome by 2035 for this scenario.

Renewables and Storage Rush Scenario Emissions Results

FIGURE 30: Renewables and Storage Rush Scenario – Total Electricity Sector Greenhouse Gas Emissions



The Renewables and Storage Rush Scenario results in 3.8 megatonnes of greenhouse gas emissions by 2035. The majority of these emissions come from combined-cycle and simple-cycle natural gas units, with a modest amount of emissions from cogeneration sources. Fuel switching, low-carbon fuel blending, and post-combustion carbon-capture could provide physical mitigation opportunities, and incremental offsets can provide a net-zero emissions outcome.

Resource Adequacy Outcomes



The AESO used a model to assess resource adequacy for set years within the AESO Net-Zero Report. In addition, the AESO evaluated sensitivities to each scenario where potential risks were identified. The AESO selected base years 2030 and 2035 to assess a full balanced view of the forecast horizon. The Resource Adequacy Model (RAM) determines the tradeoff between capacity (MW) and reliability (EUE 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*.⁵⁹

The AESO utilizes the Strategic Energy and Risk Valuation Model (SERVM) software to house its RAM. The details of the RAM's methodological approach are unchanged from the 2021 LTO.⁶⁰ 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 inertia availability. Developing robust results requires accurately characterizing the magnitude of uncertainties associated with each driver. Due to the infrequency of 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.

RESOURCE ADEQUACY SENSITIVITIES

The supply/demand mix and commensurate infrastructure to achieve net-zero emissions by 2035 in all three scenarios, from a lead-time perspective, is ambitious and adds uncertainty. Consequently, in addition to evaluating each net-zero scenario expected unserved energy (EUE) reliability metric for reference years 2030 and 2035, the AESO also evaluated and tested effects of additional sensitivities as part of the analysis. Details of the sensitivities are outlined below:

Base Case

The base case for each net-zero scenario calculates EUE based on the specified generation capacity and associated net-zero load profile.

Demand Response (DR)

DR sensitivity assumes 300 MW of incremental price-responsive load within Alberta. The AESO makes no specific assumptions around the design and implementation of any demand resource program, only that it is available at the top of the merit order to prevent lost load. This sensitivity analyzes the impact of price-responsive load on resource adequacy and grid reliability.

⁵⁹ <https://www.aeso.ca/rules-standards-and-tariff/iso-rules/complete-set-of-iso-rules/>

⁶⁰ See PDF pg. 46 of the AESO 2021 LTO.

Demand Management (DM)

There is a high degree of uncertainty around how future energy consumption profiles will evolve as different sectors of the economy electrify, particularly transportation. This sensitivity is meant to test a managed approach to EV charging. Demand Management sensitivity assumes a shift in load from on-peak hours to off-peak hours for variety of EV charging profiles.⁶¹ While the daily effect of this shift varies by season and weekday/weekend behaviours, the largest impact does reduce annual peak load by approximately 800 MW within this sensitivity.

Removal of Unabated Gas (UNG)

Unabated Gas sensitivity analyzes the impact of removing approximately 900 MW of capacity of legacy unabated natural gas-fired generation from the supply mix in 2035 in each scenario.

Removal of Storage (Storage)

For Renewables and Storage Rush Scenario, an additional sensitivity was developed to provide insight into the effect of energy storage on resource adequacy. For this scenario, 1,900 MW of battery energy storage system (BESS) and 200 MW of compressed air storage (CAS) were removed from the base case scenario.

RESOURCE ADEQUACY RESULTS

Dispatchable Dominant

As mentioned above in the Net-Zero Emissions Scenario Development section, the Dispatchable Dominant Scenario depicts significant growth in combined-cycle and simple-cycle decarbonization opportunities. For the Dispatchable Dominant Scenario, the results in Table 7 show low risk of unserved energy in 2030 and acceptable values below the threshold in 2035. Accounting for weather and economic uncertainty, this scenario shows sufficient capacity value to account for the range of forecast load outcomes. While the 2035 base case indicates increased EUE values, the sensitivities show that a reasonable amount of incremental demand response or a shift in energy consumption behaviour through demand management have a net beneficial effect for resource adequacy. The last sensitivity shows that legacy unabated gas generation still provides significant resource adequacy benefit and its removal leads to significantly increased risks of unserved energy that will need to be offset by alternative forms of energy delivery. Overall, the results show resource adequacy is something that will need to be monitored but that is not a significant concern, with many uncertainties that still need to be resolved prior to 2035. The AESO anticipates that market and policy signals closer to this period will result in more refined timing of new unit entry and retirement, such that the resource adequacy risk is minimized.

⁶¹ Light Duty Vehicle charging concentration around 5 p.m. – 8 p.m. was shifted to off-peak hours. The exact motivations for LDV load shifting can vary and could be the results of a combination of EV-specific price signals, active load management by retailer and distribution companies, and EV operating system updates that make it easier for drivers to program and optimize charging times. Medium Duty Vehicles charging used to assume evening-time depot-charging only (i.e., no daytime on-road charging). The DM sensitivity relaxes daytime charging assumptions and presents a bi-modal distribution that represents the probability of on-road/public charging for commercial MDVs. These LDV and MDV profiles are visualized in Figure 2: Electric Vehicle Charging Profiles.

TABLE 7: Dispatchable Dominant Scenario Resource Adequacy Results

EUE - MWh (Threshold)	2030 (1,069)	2035 (1,113)	Summary
Dispatchable Dominant (DD)	310	560	<ul style="list-style-type: none"> Dispatch Dominant shows no issues in 2030 and 2035 The results show higher EUE in 2035 due to increasing load and additional resource not keeping pace
DD + DR	100	225	<ul style="list-style-type: none"> Demand Response resources (~300 MW) provide a positive effect on the resource adequacy risk
DD + DM	-	120	<ul style="list-style-type: none"> Demand management provides a positive effect on resource adequacy risk
DD - UNG	-	5,200	<ul style="list-style-type: none"> Legacy unabated gas (~900 MW) provides key resource adequacy support and their absence (i.e., early retirement) is a key risk to resource adequacy

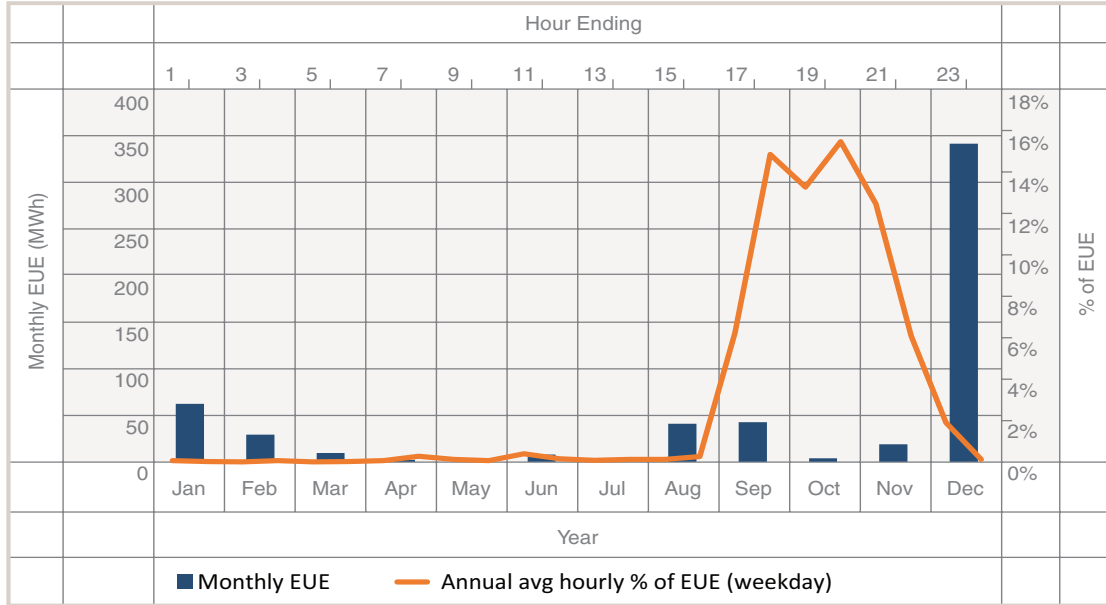
Note: The threshold is based on the AESO supply adequacy expected unserved energy metric threshold (as per ISO Rule 202.6).⁶² The **green** represents RAM results that are well under the threshold, **orange** represent results within +/- 50 per cent of threshold, and **red** represent results exceeding the threshold by more than 50 per cent.

Figures 31 through 33 below show the monthly and hourly average distribution of unserved energy in 2035 by the base case. The lower horizontal axis represents the months January through December 2035 and the corresponding left vertical axis gives the values of unserved energy (MWh) in each month. Similarly, the top horizontal axis shows the 24 hours of the day and the right vertical axis shows the percentage of unserved energy observed within the scenario corresponding to the hour of the day. This value is the average of that hour for all 12 months.

As seen in the Figure 31 below, EUE risk is concentrated during the winter months of December and January, though risk is visible through most of the year as well as peak hours between hour ending 18 and 21.

⁶² <https://www.aeso.ca/rules-standards-and-tariff/iso-rules/complete-set-of-iso-rules/>

FIGURE 31: Dispatchable Dominant Scenario Resource Adequacy Monthly/Hourly Results 2035



First-Mover Advantage

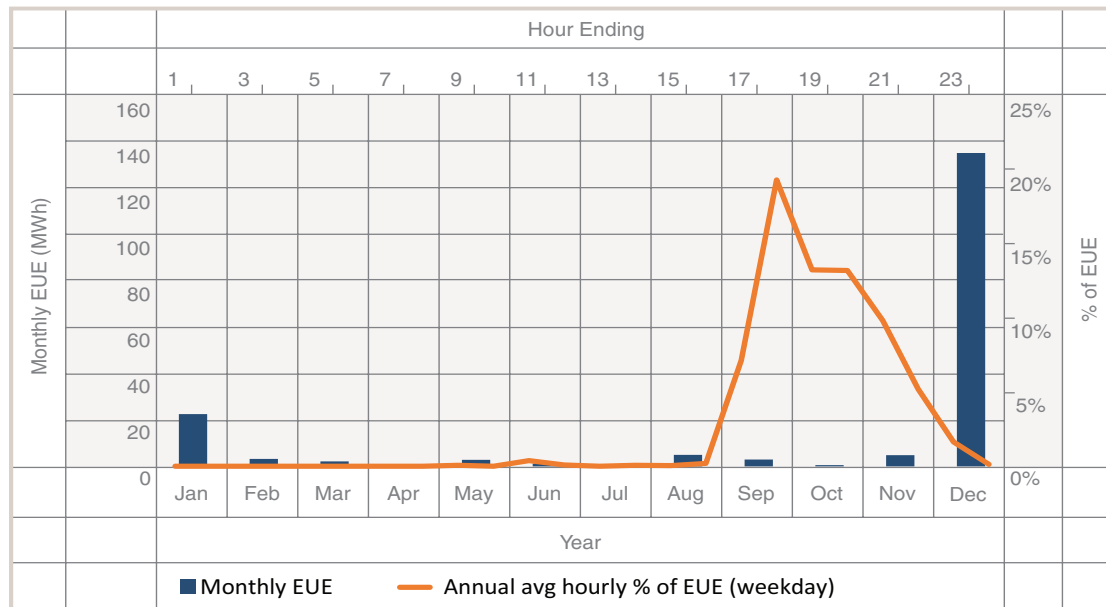
The First-Mover Advantage Scenario demonstrates a significant deployment of wind and solar intermittent renewables generation resources by 2035. For the First-Mover Advantage Scenario, the results in Table 8 show an acceptable risk of unserved energy during the 2035 forecast period and elevated risk to EUE during the 2030 forecast period. For 2030, this is generally attributed to timing assumptions around resource retirement and new capacity coming online. The scenario has sufficient resources coming online after 2030 to ensure the EUE value remains below the threshold for 2035. Sensitivities show that both incremental demand response and demand management programs are beneficial for the resource adequacy of the system. The UNG sensitivity shows that legacy unabated gas still provides significant resource adequacy benefit, and its removal leads to significant increased risks to unserved energy that will need to be offset by alternative forms of energy delivery. These results show several risk factors that should be monitored and reviewed as the energy system adapts to the resource mix transformation. In particular, the results are sensitive to resource entrance and exit timing, and energy consumption behavior.

TABLE 8: First-Mover Advantage Scenario Resource Adequacy Results

EUE - MWh (Threshold)	2030 (1,069)	2035 (1,113)	Summary
First-Mover (FM)	3,100	180	<ul style="list-style-type: none"> First-Mover shows increased EUE risk in 2030, generally due to the timing of resource retirement and new capacity coming online The results show lower EUE that meets the threshold in 2035 due to sufficient additional resource coming online after 2030
FM + DR	900	70	<ul style="list-style-type: none"> Demand Response resources (approximately 300 MW) provide a positive effect on the resource adequacy risk and improve EUE in both periods
FM + DM	-	30	<ul style="list-style-type: none"> Demand Management provides a positive effect on the resource adequacy risk and improve EUE
FM - UNG	-	3,600	<ul style="list-style-type: none"> Legacy unabated gas (approximately 900 MW) provides key resource adequacy support and their absence (i.e., early retirement) is a key risk to resource adequacy

As seen in the Figure 32 below, EUE risk is concentrated during the winter months of December and January, with some incidental risk through the rest of the year, with peak hours (HE 18-21) showing the highest risk.

FIGURE 32: First-Mover Advantage Scenario Resource Adequacy Monthly/Hourly Results 2035



Renewables and Storage Rush

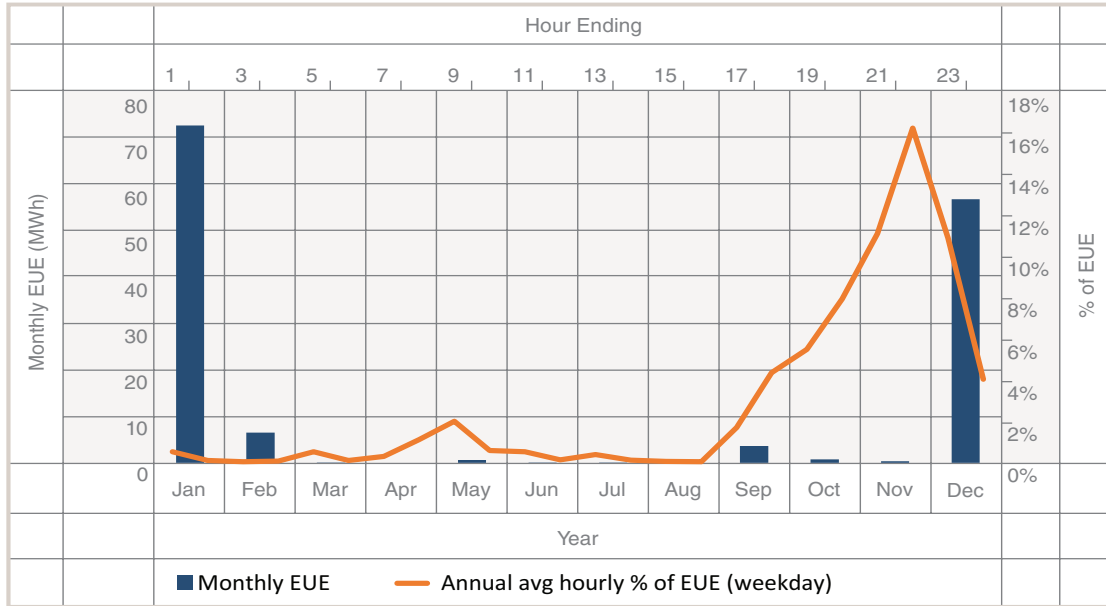
The Renewables and Storage Rush Scenario depicts the continued development of significant amounts of intermittent renewable wind and solar generation resources by 2035, with limited new low-emitting thermal generation. For Renewables and Storage Rush Scenario, the results in Table 9 show acceptable risk of unserved energy during the 2035 forecast period and elevated risk to EUE during the 2030 forecast period. For 2030, this is also generally attributed to timing assumptions around resource retirement and new capacity coming online. The scenario has sufficient resources coming online after 2030 to ensure the EUE value is well below the threshold for 2035. Sensitivities again show that both incremental demand response and demand management programs are beneficial for the resource adequacy of the system. An additional sensitivity was run with this scenario by removing approximately 2,100 MW of storage capacity. This has a similar effect on resource adequacy as removing 900 MWs of UNG from the Dispatchable Dominant and First-Mover Advantage scenarios. In addition, for Renewables and Storage Rush Scenario, the removal of a similar level of UNG shows a significantly larger EUE effect, highlighting the scenario's heightened dependence on firm capacity. These results show several risk factors that should be monitored and reviewed as the energy system adapts to the resource mix transformation. In particular, the results are sensitive to the type and timing of resource entrance and exit, and energy consumption behaviour.

TABLE 9: Renewables and Storage Rush Scenario Resource Adequacy Results

EUE - MWh (Threshold)	2030 (1,069)	2035 (1,113)	Summary
Renewables and Storage Rush (RSR)	2,400	140	<ul style="list-style-type: none"> Renewables and Storage Rush shows increased EUE risk in 2030, generally due to the timing of resource retirement and new capacity coming online The results show lower EUE that meets the threshold in 2035 due to sufficient additional resource coming online after 2030
RSR + DR	176	60	<ul style="list-style-type: none"> Demand Response (~300 MW) resources provide a positive effect on the resource adequacy risk and improve EUE in both periods
RSR + DM	-	60	<ul style="list-style-type: none"> Demand Management provides a positive effect on the resource adequacy risk and improve EUE
RSR - UNG	-	25,600	<ul style="list-style-type: none"> Legacy unabated gas (~900 MW) provides key resource adequacy support and its absence (i.e., early retirement) is an outsized risk to resource adequacy
RSR - Storage	-	3,250	<ul style="list-style-type: none"> Storage (~2,100 MW) provides value in reducing EUE risk

As seen in the Figure 33 below, EUE risk is again concentrated during the winter months of January and December, with some incidental risk through the rest of the year. The peak hours of HE 18-21 show the highest risk, though the Renewables and Storage Rush Scenario also shows some risk during the morning ramp not being present in the other two scenarios.

FIGURE 33: Renewables and Storage Rush Scenario Resource Adequacy Monthly/Hourly Results 2035



“Overall, in the 2035 forecast horizon, all three scenarios see limited risk of unserved energy due to lack of adequate supply, while risks seen in 2030 can be attributed to, and mitigated by, adjustments to the entry and exit of legacy capacity with low-emission capacity. A key risk to resource adequacy is the removal of legacy unabated gas generation. Sensitivities show its absence significantly increases unserved energy risk beyond acceptable levels if not offset by new supply with similar operating characteristics. Additional demand response and demand management also provide significant benefit in reducing supply adequacy risk.

It is important to understand that further electrification and decarbonization of the economy beyond 2035 will continue to require careful monitoring of resource adequacy.

The reader must interpret the reliability results for the years 2030 and 2035 with caution. The sensitivity cases indicate that resource adequacy modelling for periods further out can be significantly impacted by relatively minor changes in fundamental inputs. The AESO Net-Zero Report forecast assumptions contain significant uncertainty and thus will be monitored and appraised based on how the energy transition, technological and regulatory parameters shift over time. The AESO will continue to observe, review, assess, and communicate with stakeholders on the implications of changes to these and other parameters as improved information becomes available while providing sufficient time to further mitigate risks should they become more certain.

Additional Potential Reliability Challenges in a Net-Zero Emissions Power System



***“In addition to resource adequacy, there are many other factors of maintaining a reliable system that must be considered. The AESO expects that a transition to a net-zero emissions electricity grid may present operational and reliability challenges going forward, including ramping capability, sufficient inertia, frequency stability and short circuit levels across the network.*”**

As part of ramping capability, net demand variability requires the electric system to respond within a timeframe of a few minutes to an hour or two. Dispatchable generation provides the balancing capability to match the size, speed and frequency of the net demand ramps. Ramping capability, system inertia, primary frequency response and a number of other topics are assessed as part of the 2022 System Flexibility Assessment.⁶³

Many of the facets focus on frequency stability and how this will be impacted as increased amounts of inverter-based technologies (such as solar PV and battery-energy storage power resources) and small generating units (wind) are expected to displace larger synchronous generator sources (such as thermal resources like coal and natural gas generation). Maintaining frequency stability is paramount to avoiding shedding firm load after contingencies (i.e., brownouts for select consumers), minimizing impacts to operational capabilities of generation, or both. Many net-zero-enabling technologies do not provide the same levels of inertia, primary frequency response, and short circuit levels as conventional resources, and the increased concentration of inverter-based generation could present operational complexities for reliable system operations. The degree to which these operational challenges must be mitigated therefore depends on the specific net-zero supply mix.

Inertia

System inertia refers to the kinetic energy stored in rotating generators and motors that are synchronously connected to the electric system. The amount of inertia on the system is dependent on the number and size of synchronized generators and motors. Small generators and inverter-based generation provide low levels of inertia, which can result in large rates of change of frequency (RoCoF) to compensate for a supply/demand imbalance. Inertia is important on a system and regional level, and net-zero scenarios that have high levels of inverter-based generation and small generators may not provide the necessary inertial support to enable successful deployment of mitigation measures in the event of a loss of supply.

⁶³ <https://www.aeso.ca/assets/2022-System-Flexibility-Assessment.pdf>

Primary Frequency Response

Primary frequency response (PFR) refers to the automatic changes in real power production or consumption from generators, loads, and fast frequency response (FFR) resources. The speed and volume of PFR varies between types of resources, the resource's headroom (unused capacity), and the operating conditions that exist when loss of supply or demand occurs. PFR automatically reacts to arrest and stabilize locally detected changes in system frequency. Before PFR begins to react, frequency stability is maintained by the inertial response, and as PFR ramps up, the inertial response is replaced by the PFR, which also slows the RoCoF. Since many net-zero technologies are inverter-based resources, these resources may increasingly displace sources that provide stronger inertia and PFR response. Inertia and PFR are expected to be reduced more frequently as the concentration of inverter-based generation increases. Lower levels of inertia and PFR are expected to result in larger RoCoF and lower stabilization frequency, thereby requiring additional mitigation measures to offset the otherwise increased risk of under-frequency load-shedding events (i.e., brownouts triggered to rebalance frequency). System studies will define the critical inertia levels required to mitigate loss of supply considering FFR technical requirements and mitigation volumes.

Short Circuit Levels

Short circuit level is an indicator of the strength of an electrical system to reliably respond to faults or large power flow excursions that may occur on a network. It is a measure of the ability of the electric system to maintain stable voltages and reliably detect and isolate faults.

As the generation mix evolves, increased amounts of inverter-based technologies are expected to more frequently displace synchronous generator sources that have higher short circuit contribution. Grid strength is expected to trend lower as a result. System studies will help define the areas with relatively low short circuit levels that might pose reliability risks in the form of inadvertent oscillations, voltage instability, frequency instability and effectiveness of protections systems.

The AESO will monitor and evaluate the reliability impacts that these net-zero scenarios may impose on electric system operations, communicate with stakeholders and respond proactively to ensure the stable and reliable operation of the AIES.

Cost Outcomes



The AESO's Net-Zero Report incorporates high-level cost estimates relating to the additional generation capital and returns, the generation operating costs, and the additional transmission revenue requirements needed to support the generation mix in each scenario. Due to lack of direct knowledge and accountability as well as the complexity and unique attributes of distribution infrastructure, the AESO has not estimated distribution system upgrades that may be required to support increased demand associated with electrification of various sectors. As operational impacts on ramping, inertia, frequency response and system fault response were not studied in detail, the AESO has also not included estimates of any potential cost impacts for incremental ancillary services that may be required to successfully integrate a net-zero supply mix. Finally, the AESO's cost estimates do not include cost reductions or other impacts to the broader economy that may occur in other sectors as the result of a net-zero transition.

Each scenario within the AESO Net-Zero Report results in significant new generation capacity and generation capital stock turnover. The generation costs associated with each scenario have been estimated to include a 10 per cent return on capital for new facilities, return of capital for new facilities, and the expected operating costs of all operational generation. Since each of the scenarios results in a modest amount of remaining greenhouse gas emissions, payments to the carbon fund by emitting generators based on an estimated cost of offsets are included as the cost to mitigate these residual emissions. These are included as part of operating costs. In addition to the incremental capital and total operating costs associated with the generation, each scenario's diverse generation fleet is expected to require different electric transmission and distribution system infrastructure enhancements. The AESO has estimated the transmission requirements for each scenario in the cost estimates but has not incorporated the distribution system enhancement costs that may be required to enable large-scale electrification of demand.

Comparison of the net-zero scenarios with the AESO's 2021 LTO Reference Case demonstrates increased costs and dependencies on the electricity system. However, this comparison does not reflect cost reductions in other sectors, such as transportation fuels or heating fuels that may be directly related to the substitution of electricity for other sources of energy.

GENERATION COSTS (CAPITAL AND OPERATING)

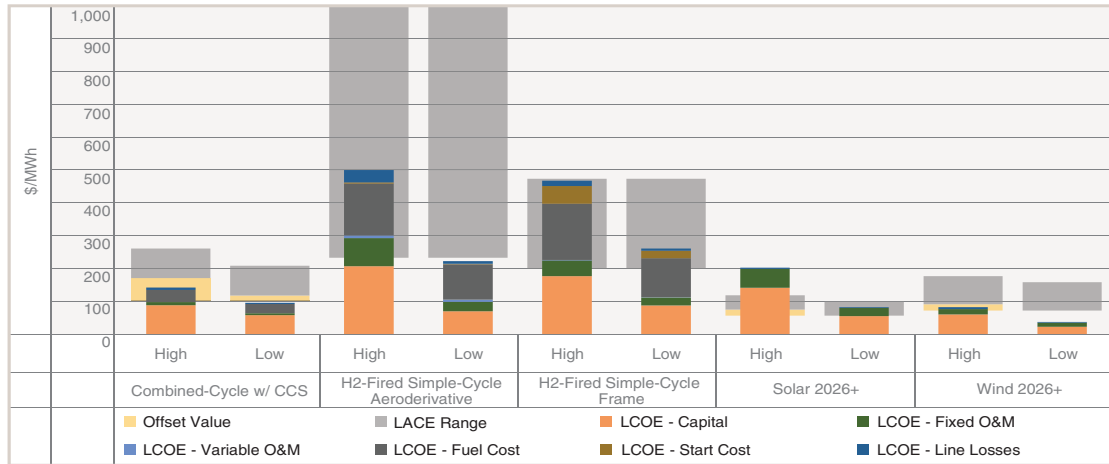
Capital costs for all simulated generation development projects were included in the cost estimates.⁶⁴ The AESO annualized the capital costs in each scenario by evaluating the periodic payment required to produce a 10 per cent return on capital. This simplistic approach allows for comparative costs between scenarios. The capital costs associated with existing capital were not included in the analysis because they are unknown historical costs, and in many cases represent fully depreciated assets.

The total operating costs of all generation were also incorporated into the cost estimates. This includes fuel costs, carbon costs, variable operating costs, and fixed operating costs.

⁶⁴ Including estimated capital costs for less than 5MW DER resources added

Levelized Costs of included Generation and Storage

FIGURE 34: Levelized Cost of Electricity and Levelized Avoided Cost of Electricity for Select Low-Carbon Generation Technologies



The Levelized Cost of Electricity (LCOE) representations include allocations for capital costs (including a 10 per cent return-on-capital), fuel costs, start costs, fixed operating and maintenance costs, variable operating and maintenance costs, line losses, and carbon costs. High and low ranges for the LCOE are depicted for each technology representing a range of simulated costs that can change based on individual unit capacity factors, commercialization dates, and operations. The LCOE estimates depict a return level required for an investor to recover a 10 per cent return on a merchant investment in the technology. The AESO expects that fully or substantially contracted facilities, such as those backed by credit-worthy corporate renewable PPAs, may enable higher degrees of debt-carrying capacity, which can lead to lower project return requirements than merchant projects. As such, the return-on-capital component of the LCOE has been reduced to five per cent for the low solar and wind range.

The levelized avoided cost of electricity (LACE) calculated ranges reflect the estimated value that can be achieved from various assets in the net-zero scenarios and represent an expected revenue range. Generally, when the LACE exceeds the LCOE for a given generation facility, it can be expected to recover its expense plus a return on capital above the stated 10 per cent investment requirement rate. The wide range of LACE included in the analysis reflects variation in avoided costs between scenarios and variation in technology operations and dispatch.

The AESO's analysis resulted in the inclusion of several different low-carbon generation technologies, including combined-cycle natural gas with carbon capture, simple-cycle hydrogen generation, solar PV, and wind generation. Within certain net-zero scenarios, each of these technologies demonstrated the ability to recover capital and operating costs, along with a return on capital. The overlap between LCOE and LACE ranges also depicts potential scenarios whereby such technologies do not recover sufficient capital returns (for example, if LCOE is greater than LACE).

Given the expected cost associated with the net-zero emissions generation technologies outlined herein, most of the technologies demonstrate potential economic applications enabling a 10 per cent return within the existing energy-only market framework. The estimated ranges also depict certain facilities that are less likely to achieve this level of return in the net-zero scenarios.

TRANSMISSION COSTS

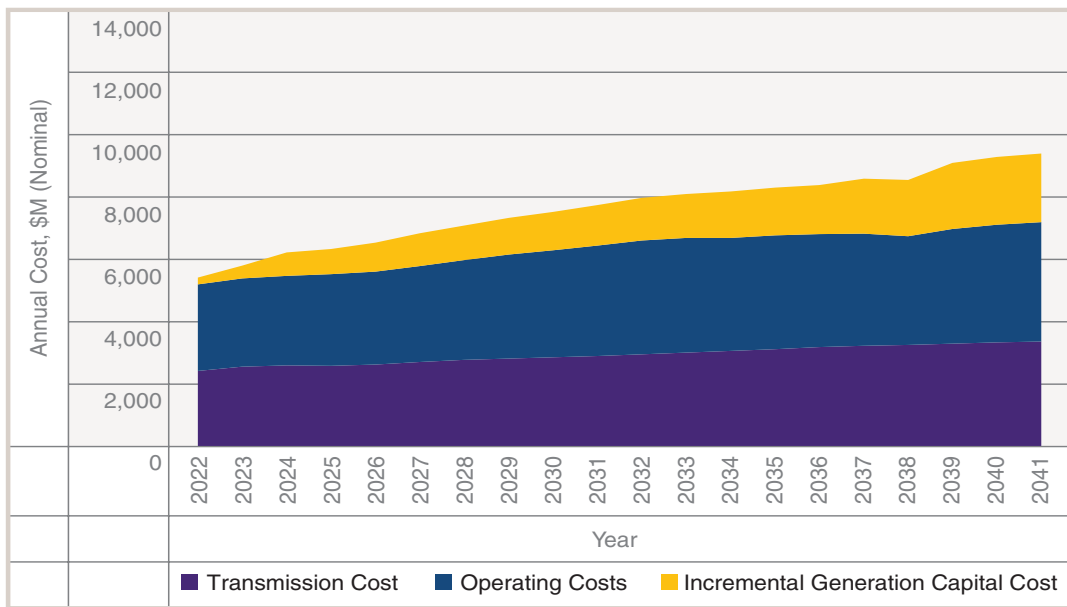
The diversity of net-zero supply scenarios lends itself to different demands on the electricity transmission system. The lead-time to plan, develop, and operationalize new transmission infrastructure is an important factor to consider in overall net-zero transition timelines. Given the varied generation sources and geographic supply changes between the net-zero options explored by the AESO, the transmission system requirements will change between each scenario. The estimated transmission capital costs incremental to those determined for the 2021 LTO Reference Case and described in the 2022 LTP associated with each scenario were annualized as incremental revenue requirements and added to the expected Transmission Rate Projection model (TRP)⁶⁵ to provide an estimate of the overall transmission revenue requirements.

The transmission cost estimates provided represent high-level results for each scenario. The forecast costs assume that generation and storage assets are located in regions that align with resource availability and interconnection capability, resulting in optimized cost assumptions. The nature of these estimates are vulnerable to cost increases resulting from higher labour and material costs or if assets locate differently than assumed.

In addition to the transmission cost increases that will be required to accommodate net-zero-enabling technologies, the AESO expects that electrification and increased demand will necessitate the requirement for significant electrical distribution system upgrades. The AESO has not forecast the impact of low-voltage end-use customer cost increases but understands that the costs associated with the electrification of transportation and heating will require substantial changes to consumer electric connections. Distribution service providers are best suited to estimate the impact of electrification on end-use customers, and in the future, the AESO will work with distribution facility owners (DFOs) to better understand these potential impacts and associated costs.

COST ESTIMATES

FIGURE 35: 2021 Long-term Outlook Reference Case Estimated Electricity Cost

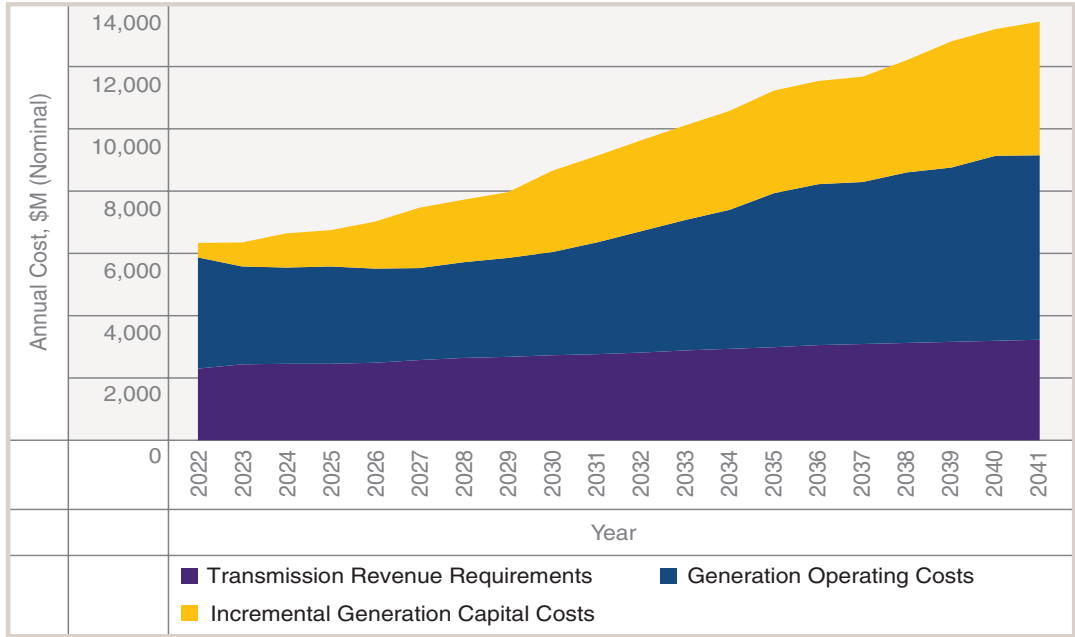


⁶⁵ The Transmission Rate Projection Fact sheet is available here: <https://www.aeso.ca/assets/Uploads/AESO-2022-TRP-Fact-Sheet-FINAL-V3.pdf>

The 2021 LTO Reference Case cost estimates are included for reference purposes. The sensitivity provides a contrast to the cost increases in the net-zero scenarios by demonstrating a non-net-zero future pathway that is less focused on reducing carbon emissions by 2035, and results in 17.7 Mt of remaining greenhouse-gas emissions. Incremental generation capital costs of \$19.5 billion⁶⁶ are forecast in the 2021 LTO Reference Case by 2041, and the operating costs associated with these assets are meaningfully lower than any of the net-zero scenarios. The lower cost exemplified in the 2021 LTO Reference Case results from lower capital and operating costs associated with conventional natural gas-fired technology supporting lower levels of electrification and demand. The 2021 LTO Reference Case was predicated on maintaining constant the current TIER “high-performance benchmark” for electricity production and \$50-per-tonne carbon pricing, escalating at two percent per annum. In addition, the transmission costs required to support the 2021 LTO are lower than those required to support the net-zero scenarios.

Dispatchable Dominant Scenario

FIGURE 36: Dispatchable Dominant Scenario Estimated Electricity Cost



The Dispatchable Dominant Scenario cost estimates incorporate \$40 billion⁶⁷ of capital investment in generation technology between 2022 and 2041. This generation capital investment is largely concentrated between hydrogen-fired, combined-cycle with CCS, and cogeneration. Modest amounts of capital for renewables, DERs, and energy storage also make up a small portion of the incremental generation capital costs. The AESO has annualized the investment costs using a periodic payment function, including a 10 per cent return on capital. Total operating costs for the scenario incorporate a significant amount of hydrogen fuel, natural gas fuel, carbon fund credits (for compliance with TIER), variable operating costs, and fixed operating costs.

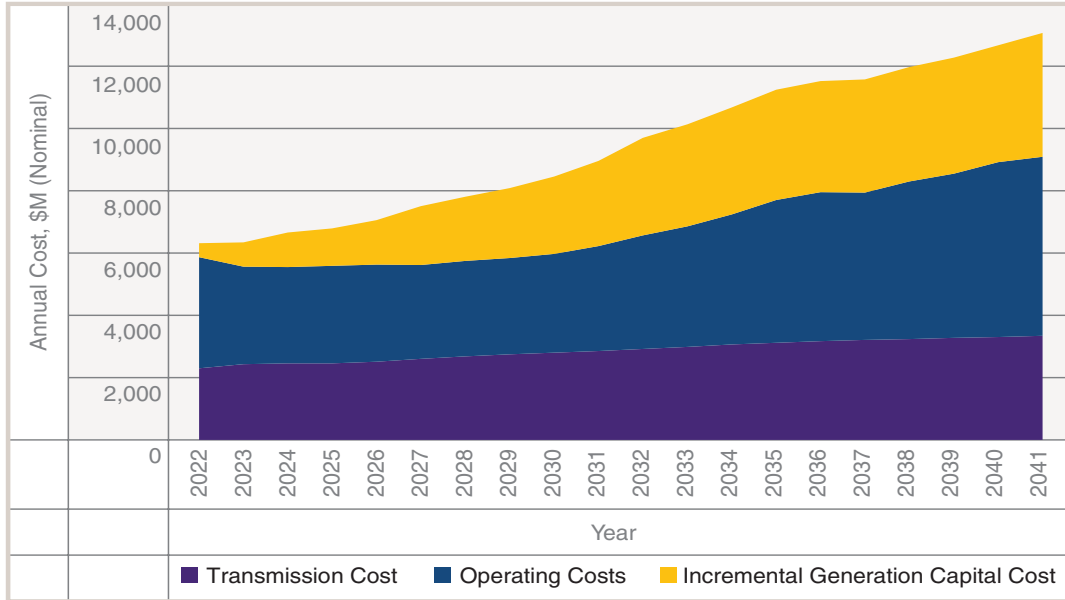
The transmission capital cost estimates represent an incremental \$0 to \$500 million of expenditure in the Dispatchable Dominant Scenario compared to the 2021 LTO Reference Case. The AESO has annualized the value of transmission capital using cost-of-service rate estimates and added these to the revenue requirements for existing capital.

⁶⁶ This capital cost does not include a 10 per cent return on capital, but rather reflects the cash spent on generation developments.

⁶⁷ This capital cost does not include a 10 per cent return on capital, but rather reflects the cash spent on generation developments.

First-Mover Advantage Scenario

FIGURE 37: First-Mover Advantage Scenario Estimated Electricity Cost



The First-Mover Advantage Scenario includes the development of \$37 billion⁶⁸ of new generation assets between 2022 and 2041. The incremental generation capital costs are diversified between renewables and dispatchable low-carbon generation sources, and include a modest amount of energy storage capital. Figure 37 represents the annualized cost of new generation capital, inclusive of a 10 per cent return.

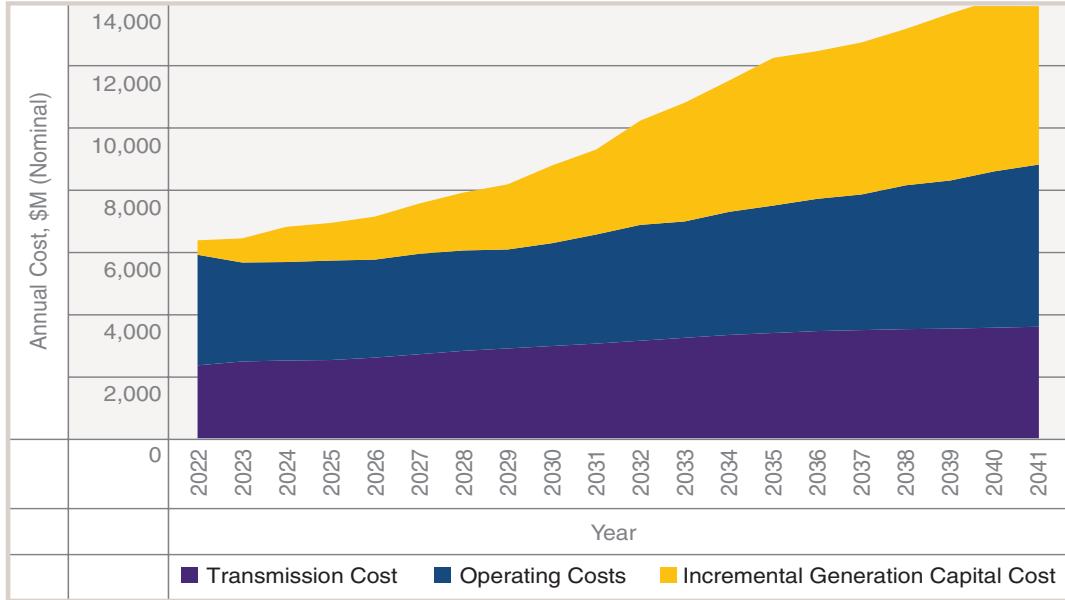
The higher penetration of renewables generation in this scenario results in lower annual operating costs than in the Dispatchable Dominant Scenario. However, this scenario still relies on significant volumes of hydrogen fuel post-2030, which increases generation operating costs compared to the Renewables and Storage Rush Scenario.

Transmission capital costs in this scenario are expected to be approximately \$1.5 billion higher than the 2021 LTO Reference Case as a result of increased renewables integration infrastructure.

⁶⁸ This capital cost does not include a 10 per cent return on capital, but rather reflects the cash spent on generation developments.

Renewables and Storage Rush Scenario

FIGURE 38: Renewables and Storage Rush Scenario Estimated Electricity Cost



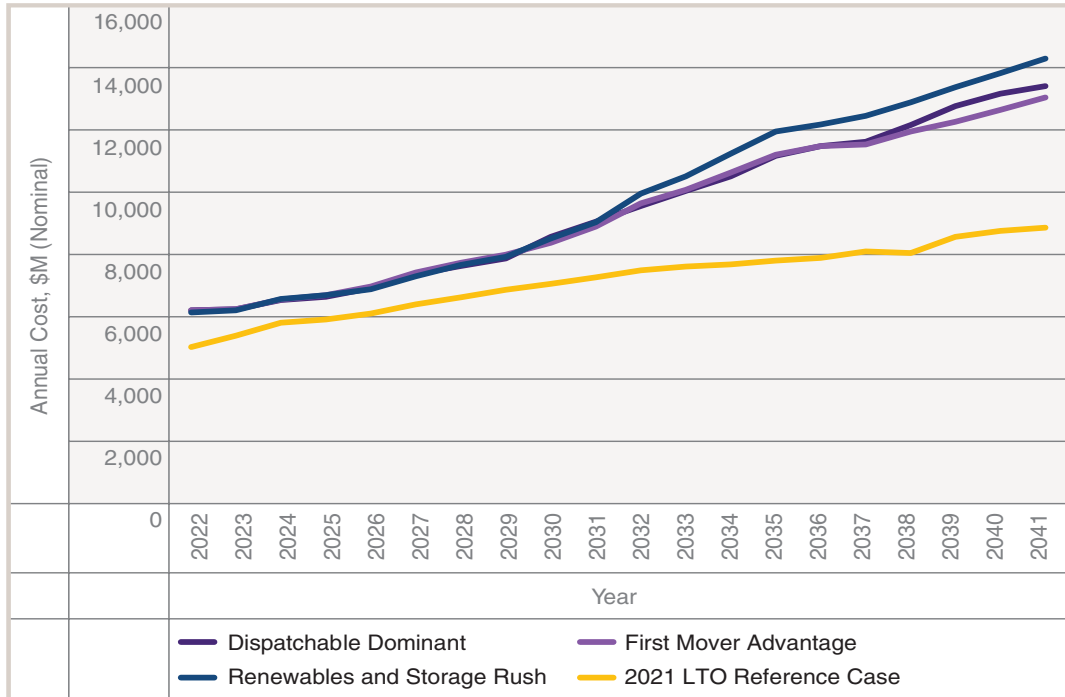
The Renewables and Storage Rush scenario includes \$51 billion⁶⁹ in generation and storage capital expenditure between 2022 and 2041. Almost half of the generation capital is related to the development of wind and solar generation in this scenario, with a notable \$12 billion of storage asset investments.

While capital costs associated with the Renewables and Storage Rush Scenario are higher, the operating costs were the lowest among the net-zero scenarios. This result stems from the low operating costs associated with wind and solar generation, and the ability to charge storage assets while low-cost surplus generation is available.

The required transmission capital costs to support the generation and storage assets in this scenario were the highest in the Net-Zero Pathways Analysis, enabling the largest integration of wind and solar assets. Approximately \$3 billion of incremental transmission costs were forecast compared to the 2021 LTO Reference Case.

⁶⁹ This capital cost does not include a 10 per cent return on capital, but rather reflects the cash spent on generation developments.

FIGURE 39: Estimated Electricity Cost



The cost of electricity for each scenario was estimated as the sum of incremental generation capital costs, generation operating costs, and total transmission revenue requirements. Measured in this way, the Renewable and Storage Rush Scenario represented the highest cost among the net-zero scenarios, while the First-Mover Advantage Scenario represented the lowest cost. The cost composition differs between the net-zero pathways scenarios, but the total costs between scenarios are within five per cent of each other. The cost of each of the net-zero scenarios was estimated to be 42 to 52 per cent higher than the 2021 LTO Reference Case in 2035. The higher cost estimates are attributable to increased energy demand, integration of higher cost generation technology, and increased transmission system requirements.

FIGURE 40: 2035: Estimated Electricity Cost by Scenario

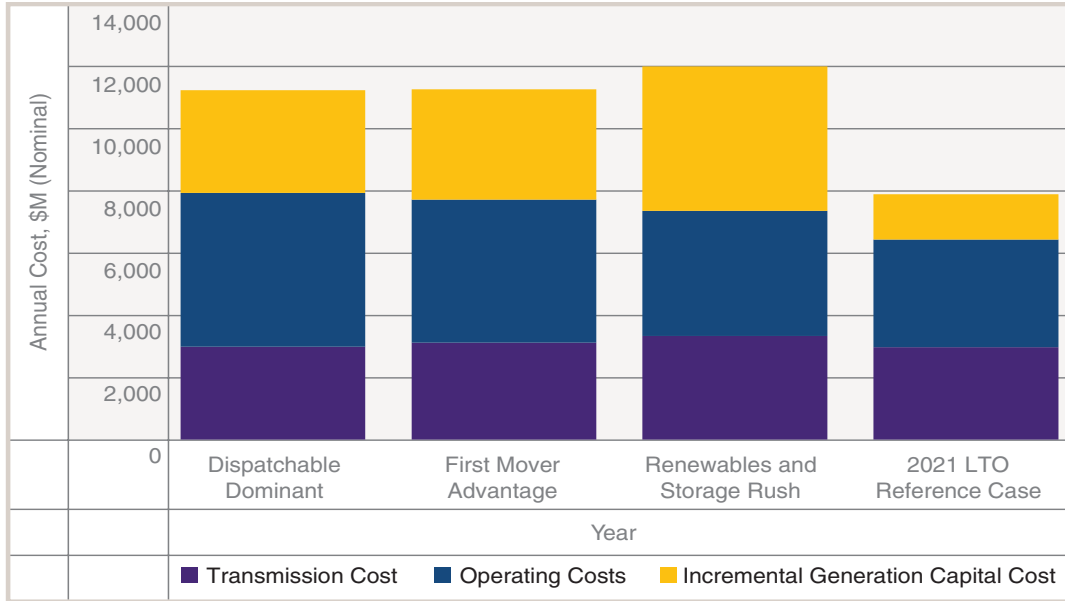
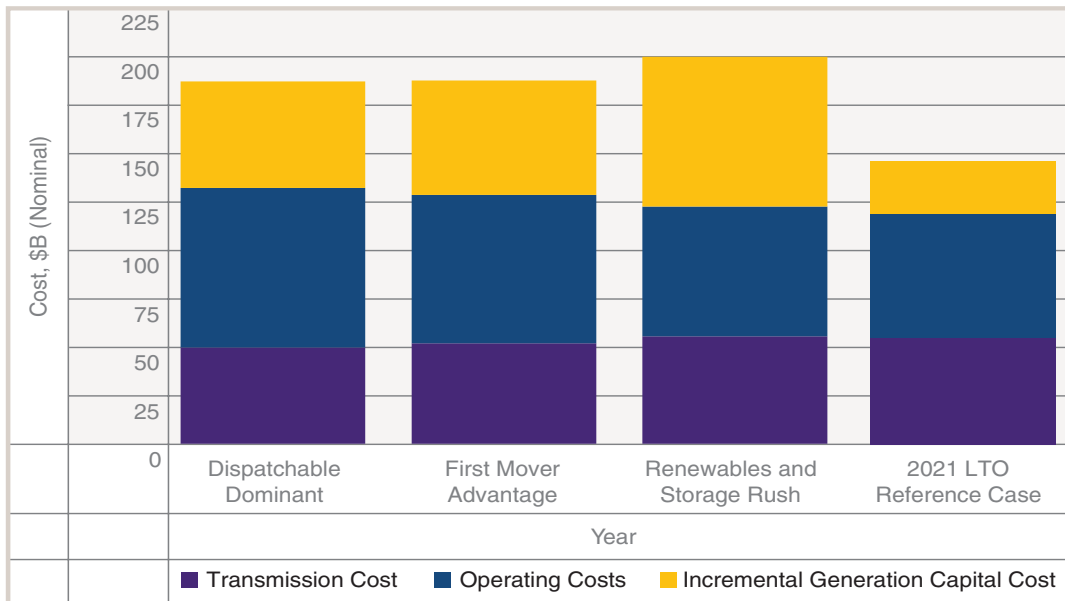
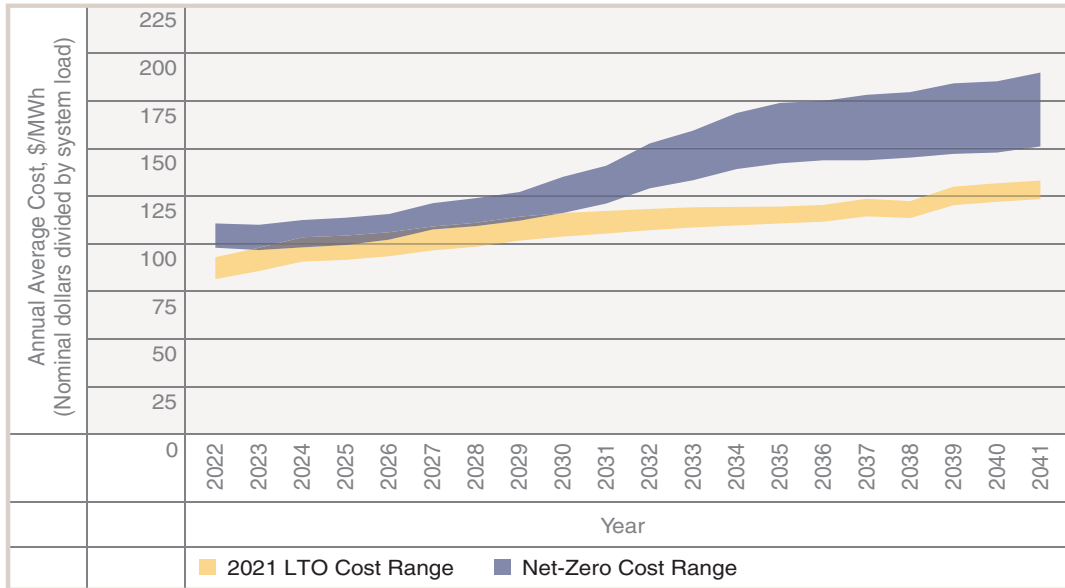


FIGURE 41: 2022 to 2041 Cumulative Electricity Cost by Scenario



Over the 20-year period of study, from 2022 to 2041, the expected cost increase from the 2021 LTO Reference Case to achieve the net-zero scenarios is between \$44.1 billion and \$52.1 billion, representing a relative increase in costs of 30 to 36 per cent. The majority of the costs are related to return-on and return-of generation capital (59 to 71 per cent) and generation operating cost increases (20 to 41 per cent). Less than 10 per cent of the incremental costs are related to transmission revenue requirements stemming from additional transmission system investments in the net-zero scenarios.

FIGURE 42: Normalized Electricity Cost



“The total costs of the net-zero scenarios are within a modest range of one another, with the First-Mover Advantage being the least costly and the Renewables and Energy Storage Rush being the most costly. Although total costs are tightly rangebound, the composition of the costs in each scenario varies. In comparison to the 2021 LTO Reference Case, all three scenarios’ aggregated costs are materially higher.”

To obtain an estimate of system costs normalized per unit of electricity consumption, the high-level incremental generation capital costs (excluding sub-5 MW DER additions), additional operating costs and transmission revenue requirements associated with the AESO’s highest and lowest cost net-zero scenarios were divided by a range of system load estimates (between 65 per cent and 75 per cent of AIL). A similar calculation was applied to the 2021 LTO Reference Case, as a comparative non-net-zero scenario. Normalized cost results through time based on this calculation are provided in Figure 42 above. Based on this, the unit cost of electricity for net-zero scenarios may be 40 per cent higher than the 2021 LTO Reference Case by 2035. It is important to note that costs calculated in this way are not meant to represent a market price forecast or the delivered cost of electricity but rather illustrate long-term trends based on the included cost components while factoring in the growth in the load base they may be distributed across.

Conclusion



Alberta's electricity sector will play a critical role in achieving economy-wide emissions reductions through decarbonization of generation sources and increasing electrification across economic sectors.

Emissions Reductions

Under all three scenarios, by 2035 the Alberta electricity system could approach zero emissions; however, it is anticipated that a small volume of emissions would remain due to the continued operation of some unabated assets as well as residual emissions, since carbon-capture technologies do not capture 100 per cent of emissions. Two approaches can be taken to close this remaining gap and achieve net-zero: the use of emissions offsets or credits or physical abatement via retrofits or replacement of unabated assets. Either approach could result in a net-zero emissions electricity sector by 2035, and the AESO expects that ultimately the lowest cost alternatives will be adopted by large emitters in the electricity sector. However, full physical abatement across all assets is likely to be operationally unrealistic (for example due to residual emissions under CCS technologies) and consequently marginal physical abatement costs are likely to escalate rapidly as sector emissions trend toward zero. As such, the AESO does not anticipate that zero physical emissions will be achieved by 2035, pointing to a role for offsets in achieving net-zero.

Resource Adequacy

Under all three scenarios, directional indications are that resource adequacy can be achieved in 2035, though the AESO would note the continued electrification and decarbonization of the economy beyond 2035 may pose challenges on this front. A key risk to resource adequacy is the exit of legacy unabated gas generation. Sensitivities show its absence within the study period significantly increases unserved energy risk beyond acceptable levels if not offset by new supply with similar operating characteristics. Increased load flexibility in the form of incremental demand response during tight supply conditions and demand management, which can assist in shifting energy consumption from peak to off-peak hours, can act to significantly reduce supply adequacy risk. Each of the three scenarios studied indicated that peak winter conditions generally showed the highest risk of unserved energy.

Given that each scenario has a high degree of uncertainty as to how it unfolds, and that asset owners will make the decision to build and/or retire assets, resource adequacy results must be considered directional. Furthermore, given the complexity of the new abated thermal technologies, including the lead-time required to develop and construct new supply resources and supporting infrastructure, there is the potential that some units in the outlook may be delayed. This may extend the life of an unabated thermal asset beyond the indicated timelines provided. For example, a coal-to-gas converted unit may not retire until its regulated end-of-life date if the reliability and subsequent economics of the system indicate so. The risk drivers will be monitored by the AESO and provide the space to respond and mitigate risks should they become more apparent.

Costs

The high-level cost estimates provided in the AESO's Net-Zero Report demonstrate that the diverse technological pathways that can be followed to reduce electricity sector emissions have the potential to increase system costs materially. Relative to the non-net-zero 2021 LTO Reference Case, incremental costs of \$44 to \$52 billion (nominal, undiscounted) for generation capital including return, generation operating costs and transmission revenue requirements are required. This represents a 30 to 36 per cent increase relative to the LTO baseline. Comparatively, the Dispatchable Dominant, First-Mover Advantage, and Renewables and Storage Rush scenarios demonstrate a similar cost trajectory despite the different emissions reduction strategies employed in each scenario. Cumulative costs from 2022-2041 are within 5 per cent between all three scenarios.

Given the relatively immature nature of certain generation technologies assessed in the AESO's Net-Zero Report Analysis, a degree of caution should be taken in interpreting cost results. Technological costs and operational performance of emerging technologies could deviate materially from the estimates used in the report. The AESO has also not been able to estimate costs in all electric system categories, with distribution system costs being the most notable.

Regardless, one cost outcome is that a net-zero transition which simultaneously increases electricity demand and requires the existing capital stock to be replaced or supplemented with higher capital cost net-zero emitting alternatives could impose significant cost increases in the electricity sector. However, certain costs may represent transitional costs from other sectors to the electricity sector, making the net cost impact to consumers difficult to assess given that the AESO's modelling framework focuses only on the electricity system. For example, electrification of heating or transportation may increase electricity costs while simultaneously reducing costs for natural gas and transportation fuels. Other expenses associated with decarbonization may be more incremental in nature, such as new generation capital costs, hydrogen fuel costs, or carbon capture costs.

Next Steps

The AESO is committed to providing timely analysis and insights regarding the net-zero transformation. The AESO expects to follow this analysis with the following activities during the 2022 to 2024 period and will inform stakeholders as appropriate as they progress:

- 1.** Continue to monitor and participate in the development conversation around policy initiatives such as the Clean Electricity Standard (CES) and Technology Innovation and Emissions Reduction (TIER)
- 2.** Develop a reliability requirements roadmap for future reliability services needed to support the future resource transformation and identify potential operational and reliability challenges (such as frequency stability, short circuit levels, managing ramp and variability). This would include operational impact assessments⁷⁰ that utilize high renewables scenarios and identify the options available to enable these requirements through rule or market design change and the integration of high renewables levels (2023).
- 3.** Based on the AESO Net-Zero Report assessment and subsequent reliability requirements assessment, implement enhancements to the Market Evolution Roadmap. Identify other required market initiatives to support long-term sustainability and competitiveness of the energy-only market structure, based on output from carbon policy analysis and assessments. Such activities will be communicated to stakeholders as they progress.
- 4.** A net-zero transition is anticipated to have significant effects on both the transmission system as well as the distribution system. The AESO will continue to engage with DFOs to work together to better understand the impacts and potential costs of carbon policy analysis and assessments to distribution systems.
- 5.** Incorporate additional and increasingly more refined net-zero scenarios, including reflection of CES and TIER policy details as applicable, into the 2023 LTO. The 2024 LTP will provide a plan for future transmission development to continue to support a transformed resource mix as envisioned within the 2023 LTO.

⁷⁰ Factors assessed are expected to be similar to those examined in the June 2022 Flexibility Report, which assessed the 2021 LTO Reference Case and Clean-Tech Scenario (<https://www.aeso.ca/assets/2022-System-Flexibility-Assessment.pdf>)

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