Alberta Utilities Commission

# AUC inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta

## Module B Report

March 28, 2024

**Alberta Utilities Commission**
AUC inquiry into the ongoing economic, orderly and
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Module B Report
Proceeding 28542

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## 1 Executive summary

1. This is the report of the Alberta Utilities Commission (AUC or the Commission) on the reliability and affordability issues in the inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta. The Commission determined that the inquiry would be separated into two modules to explore the issues identified in the order-in-council. In Module B, the Commission considers the impact the increasing growth of renewables has to both generation supply mix and electricity system reliability.

2. The Commission issued a notice on October 24, 2023, outlining its process for Module B. As part of the process, the AUC commissioned two expert reports to assist it in considering the issues. The process was completed on February 29, 2024, with parties providing written submissions on the AUC-sponsored expert reports.

3. The transition of the electricity system is often described as a balance between three pillars: decarbonization, affordability and reliability. Each pillar is crucial but often interlinked with the other pillars. Alberta is currently working to decarbonize its electric system while minimizing the impacts to affordability and reliability.

4. The Commission recognizes that renewables will play an important role in transitioning Alberta's electric system to net zero. However, the intermittent nature of renewables, as well as other characteristics of inverter-based resources, will have increasing impacts to the grid as they make up a larger portion of Alberta's generation supply mix.

5. Based on the expert reports and the submissions made by participants in Module B, the Commission makes the following observations:

*Observations:*

- Renewables are impacting many different aspects of system reliability. The Alberta Electric System Operator (AESO) is currently assessing options to address key areas of reliability in the short term.

- Under the current market design, expected unserved energy in the late 2030s is significant and there is potential for unprecedented load-shed events. An increased rate of decarbonization, i.e., net zero by 2035 instead of by 2050, will exacerbate supply adequacy issues.

- Under the current energy market design, increased renewables will exacerbate supply adequacy issues.

- Renewables lower pool prices and increase volatility, reducing the signal for dispatchable generation to enter the market.

- Newer low-carbon technologies could be considered first-of-a-kind and have a greater level of associated risk, particularly under a target to decarbonize by 2035.

- Energy storage can play a role in reducing supply adequacy issues but is not a complete solution and is not expected to be economic under the current energy market and AESO tariff.

- Given the scale of expected unserved energy, minor changes to supply mix assumptions do not alleviate supply adequacy concerns.

- Under the current market design, pool prices are initially stable, but are then expected to increase at a rate above inflation in the 2030s. An increased rate of decarbonization, i.e., net zero by 2035 instead of by 2050, will exacerbate affordability issues.

- Demand response has some potential to mitigate supply adequacy impacts and reduce future costs to electricity consumers.

- Investors are concerned about the current level of policy uncertainty.

- By the late 2030s, under the existing market framework, consumers would be paying significantly higher rates for electricity, while receiving a substantially lower level of reliability. Given this, changes to the market design and policy framework are necessary.

6. The Commission also makes the following commitment:

*AUC Commitment:*

- The Commission will explore demand response opportunities, including exploring time varying rates as a priority item in the near term.

7. The Commission has attached the two expert reports. All submissions from parties on those reports have been available throughout on the Commission's public electronic filing system in Proceeding 28542.

8. On March 11, 2024, the Minister of Affordability and Utilities directed the AESO to work with industry and stakeholders to design a restructured energy market.[1]

9. The Commission will ultimately be the adjudicator of proposed rule changes put forward by the AESO and, as such, it will not comment on the merits of potential changes proposed. But

[1] Direction Letter from the Minister of Affordability and Utilities, March 11, 2024. https://www.aesoengage.aeso.ca/37884/widgets/156642/documents/125532.

as stated above, and for the reasons set out in this report, the Commission considers that changes to the market and policy framework are necessary.

10. While the most extreme effects on reliability and affordability may not appear until the late 2030s, the Commission recognizes that changes to markets and policy will take time. It assumes the government, the AESO, the Market Surveillance Administrator (MSA) and stakeholders will move forward in a timely manner so investors and participants have the necessary policy certainty going forward to confidently make decisions and allow Alberta's market to succeed in a way that will protect Albertans' interests.

## 2 Background

11. On August 2, 2023, the Government of Alberta issued an order-in-council directing the AUC to hold an inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta. The order-in-council can be found in Appendix 1.

12. The order-in-council directed the Commission to inquire into and report to the Minister of Affordability and Utilities on the following:

1. Considerations on development of power plants on specific types or classes of agricultural or environmental land.

2. Considerations of the impact of power plant development on Alberta's pristine viewscapes.

3. Considerations of implementing mandatory reclamation security requirements for power plants.

4. Considerations for development of power plants on lands held by the Crown in Right of Alberta.

5. Considerations of the impact the increasing growth of renewables has to both generation supply mix and electricity system reliability.

13. The Commission determined that the inquiry would be separated into two modules to explore the issues identified in the order-in-council. Module B addresses issue 5.

14. Following the order-in-council, the Ministry of Affordability and Utilities issued a press release and fact sheet that emphasized the government's interest in also considering the affordability impacts of increasing renewable generation.[2] The Commission has also incorporated that into the scope of this report.

15. In addition to the Commission's inquiry, the Minister of Affordability and Utilities has requested that the AESO and the MSA consider whether potential changes to Alberta's energy-only market are required. On March 11, 2024, the Minister of Affordability and Utilities

[2] Alberta Ministry of Affordability and Utilities. AUC approvals pause for renewable projects, August 25, 2023. https://www.alberta.ca/release.cfm?xID=88843C2191BF5-097B-B1C7-82E755C07EF645A1

requested the AESO to work with industry and stakeholders to design a restructured energy market.

## 2.1 Process

16. On October 24, 2023, the Commission issued a notice for Module B of the inquiry, outlining its proposed process. As part of the process, the AUC commissioned and made public two expert reports to assist it in considering the issues. The list of experts and scope of their reports is set out below.

| Expert | Scope of report |
|---|---|
| London Economics International LLC (LEI) | • Review and assess prior studies that evaluate the evolution of the Alberta electric system from a technical and/or economic perspective in order to inform reliability and affordability questions.<br>• Following stakeholder engagement, development of a technical, simulation-based assessment of future wholesale market fundamentals under the current energy market design over the long term to evaluate future system reliability (e.g., resource adequacy) and consider electric utility bill impacts for retail customers. |
| FGS Longview | • Using targeted stakeholder engagement and other means, gauge current perception of Alberta’s power market by relevant generation developers (incumbent and non-incumbent) and sources of capital to review attractiveness of Alberta's market structure, views on potential market structure changes, and appetite for merchant power risk.<br>• Identify the drivers behind stakeholder perception of Alberta’s power market. |

17. The AUC held two technical meetings as part of the process. The first, held on November 9, 2023, was to discuss and obtain feedback on LEI’s simulation-based assessment. At the second technical meeting, held on February 14, 2024, the experts presented a summary of their reports and interested parties had the opportunity to ask questions of the experts.

18. The AUC published the expert reports on February 7, 2024. The final step of the process occurred on February 29, 2024, with parties providing written submissions on the expert reports.

## 2.2 Ministry and agency roles

19. In October 2022, the Government of Alberta established the Ministry of Affordability and Utilities. Its responsibilities include managing and developing policy for the utilities sector and overseeing a reliable and affordable electricity system for Albertans. The ministry is responsible for several agencies that oversee the utilities sector including the AUC, the AESO and the MSA.

20. The AUC is an independent quasi-judicial agency responsible for ensuring that the delivery of Alberta’s utility services takes place in a manner that is fair, responsible and in the public interest. The AUC regulates the utilities sector to protect social, economic and environmental interests of Alberta where competitive forces do not. The AUC, among other

responsibilities, ensures that electric generation and transmission facilities are constructed and operated in a safe, reliable, efficient and environmentally responsible way, and provides regulatory oversight of issues related to the development and operation of the wholesale electricity market in Alberta.

21. The AESO is responsible for the safe and reliable operation of the Alberta Interconnected Electric System. It serves a number of specific functions including:

- Managing and operating the provincial power grid.
- Planning and operating the electricity market.
- Planning the future of the electricity system and its infrastructure.
- Connecting generators and large power consumers to the transmission system in a safe and reliable manner.

22. The MSA is a public agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's electricity market. The MSA monitors the performance of Alberta's electricity market to ensure that market participants comply with all applicable legislation, the Alberta reliability standards and the independent system operator's rules.

## 3 System reliability

**Observation: Renewables are impacting many different aspects of system reliability. The AESO is currently assessing options to address key areas of reliability in the short term.**

23. System reliability is a broad topic including many different components. The AESO is the agency primarily responsible for the reliability of the transmission system. Last year, the AESO released the *2023 Reliability Requirements Roadmap*,[3] which focuses on three key areas of reliability: frequency stability, system strength and frequency capability. The Commission recognizes that increasing renewable generation is impacting each of those areas and the AESO has indicated that addressing each area is a high priority.

24. Given the AESO is currently assessing options to address those areas, the Commission decided that considering those aspects of system reliability would ultimately be duplicative. Accordingly, the Commission scoped LEI's work to focus primarily on supply adequacy. LEI defined supply adequacy as "having enough electricity generation supply to meet hourly demand, taking into account planned and unplanned outages and other factors that may impact demand or supply." Many parties submitted that because of this limited scoping, the LEI Report underestimates system reliability issues. The Commission acknowledges this and emphasizes that the absence of discussion within this report on other aspects of reliability is not intended to imply a lower level of importance of those aspects or that there is less urgency to addressing them. The Commission encourages the government to consider the AESO's work, in conjunction with this report, to fully appreciate the impact of renewables on system reliability.

[3] AESO 2023 Reliability Requirements Roadmap.

### 3.1 Supply adequacy

25. London Economics International LLC (LEI) conducted a forward-looking analysis to project future market outcomes and analyze the impact of renewable energy generation on supply adequacy.

26. The decarbonization of the electricity sector will have a profound impact on the generation supply mix with renewables expected to significantly increase. LEI's analysis began with two base cases representing two different decarbonization policy pathways for the Alberta electricity sector: decarbonization by 2035 and decarbonization by 2050. The 2035 Base Case was designed to reflect the federal draft *Clean Electricity Regulations*;[4] the 2050 Base Case was designed to be consistent with the province's Alberta Emissions Reduction and Energy Development Plan.[5]

**Observation: Under the current market design, expected unserved energy in the late 2030s is significant and there is potential for unprecedented load-shed events. An increased rate of decarbonization, i.e., net zero by 2035 instead of by 2050, will exacerbate supply adequacy issues.**

27. The LEI Report[6] finds that reliability is expected to be worse under the 2035 Base Case than the 2050 Base Case. However, under both cases, by the late 2030s the level of reliability is expected to be materially worse than the level Albertans have been accustomed to for decades. The LEI Report indicates that insufficient supply levels result in the potential for unprecedented load shed in Alberta under the current electricity market design, even under normal weather conditions.[7] Under abnormal weather events, that expected load shed is even higher.

28. LEI's analysis forecasted expected unserved energy, which measures the number of megawatt hours (MWh) of load that will not be served in a given year as a result of insufficient available capacity. As shown in the figure below, the expected unserved energy is expected to peak in 2038 once the last of the coal-to-gas power plants retires and is significantly above the AESO's resource adequacy threshold.[8]

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4 Government of Canada. Canada Gazette, Part I, Volume 157, Number 33: *Clean Electricity Regulations*. August 19, 2023. The Commission notes that since the release of the LEI Report, the federal government has provided an update proposing to relax some of the restrictions in the regulations.

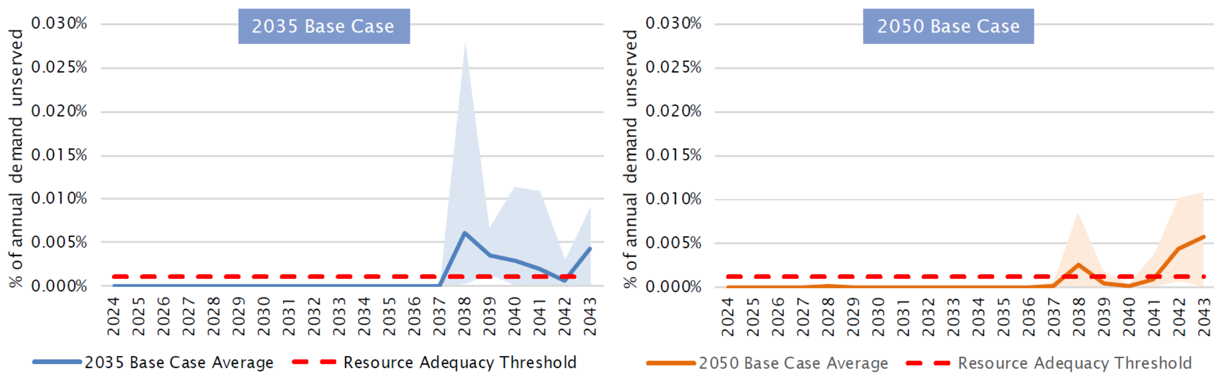
5 Government of Alberta. Alberta emissions reduction and energy development plan. April 2023 (updated January 2024).

6 Exhibit 28542-X0049.01, Expert Report - London Economics International - Cover Report; Exhibit 28542-X0050, Expert Report - London Economics International - Annex 1 - Scenario Analysis; Exhibit 28542-X0051, Expert Report - London Economics International - Annex 2 - Projection of Residential Electric Bills; Exhibit 28542-X0052.01, Expert Report - London Economics International - Annex 3 - Probabilistic Supply Adequacy Analysis.

7 LEI stated that it used "actual weather data in its long term energy market modeling, in order to ensure realistic conditions. LEI chose to use 2021 weather conditions (which impacted hourly renewable generation and hourly variation in load) to represent "normal" weather, because 2021 conditions were closest to longer term averages and were neither mild nor abnormally extreme in terms of weather factors that could skew the scenario analysis results towards low likelihood events."

8 The AESO defines the Resource Adequacy Threshold as the one-hour average Alberta internal load for a year divided by 10.

**Figure 1. Comparison of levels of demand unserved under the base cases with normal weather**[9]




Notes:

- LEI ran its simulation model 10 times (seeds) for each year and scenario, with varying patterns of generation outage schedules. The shaded areas in the charts above represent the range of modeled outcomes caused by these different patterns of generation outages. The solid lines represent the average across the 10 seeds.

- AESO defines the Resource Adequacy Threshold as the 1-hour average Alberta internal load for a year divided by 10. Converting to percentage terms is calculated as 1/8760/10 = 0.00114%.

29. LEI developed additional scenarios based on five years of historic data to evaluate supply adequacy during abnormal weather events. These weather scenarios, combined with different scenarios for generation outages, resulted in an average expected unserved energy in 2038 of 30,491 MWh for the 2035 Base Case or 16,793 MWh for the 2050 Base Case. As to be expected, these levels are higher than those in the modelling under normal weather conditions shown in the figure above, and well above the AESO's resource adequacy threshold of 1,135 MWh.

30. Albertans have long enjoyed high reliability in terms of supply adequacy, and even levels of unserved demand at the AESO's resource adequacy threshold would be unprecedented. For context, the AESO's most recent long-term adequacy metrics indicate a probability of supply adequacy shortfall of approximately zero MWh for the next two years.[10] The Commission notes that the number of grid alerts[11] has increased in recent years but that even the most severe events, such as the one that occurred on January 13, 2024, have not yet resulted in any unserved load.

31. Parties identified that the AESO currently has the authority to take preventative actions including procuring load-shed services, backup generation and emergency portable generation. The emergency alert issued on January 13, 2024, in which Albertans responded by quickly reducing approximately 200 megawatts (MW) of demand, is a prime example. Parties submitted that the LEI analysis did not use these tools to mitigate supply loss and, as such, overestimates the extent of the issue. The Commission agrees that such tools could be used to mitigate issues, however, given the scale of expected unserved energy, the Commission considers that those tools on their own would not be sufficient.

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[9] Exhibit 28542-X0049.01, Expert Report - London Economics International - Cover Report, PDF page 15.

[10] Exact number is 0.06 MWh. AESO Long-term adequacy metrics – February 2024. https://www.aeso.ca/download/listedfiles/2024_02_LTA.pdf.

[11] The AESO issues a Grid Alert when the power system is under stress and we're preparing to use emergency reserves to meet demand and maintain system reliability.

32. The LEI Report states that in the five per cent most severe supply adequacy events, nearly 10 per cent of demand would not be met, with unserved load events that last for almost an entire day (23 hours). The system is projected to have the highest reliability risk during evening hours in the winter months, arguably when electricity is needed most.

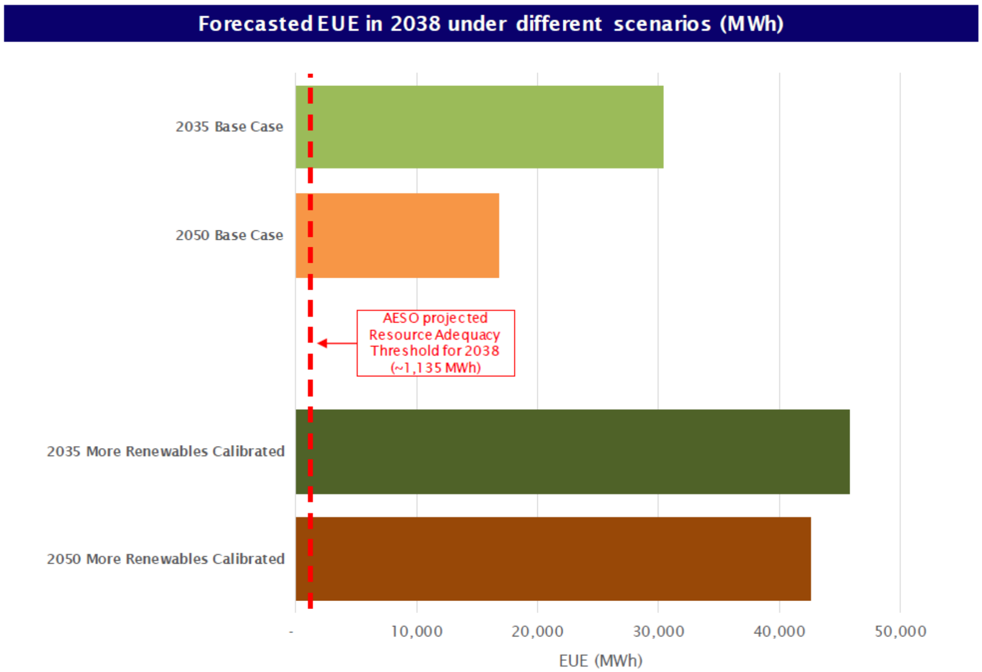
33. The addition of more than 2,000 MW of natural gas generation in 2024 is expected to largely address supply adequacy concerns in the near term. However, the LEI Report identifies that there is a potential for unserved load in the next five years under abnormal weather conditions if low prices result in the significant retirement of coal-to-gas power plants.

34. Parties criticized the LEI Report for assuming that the current energy-only market and policy would remain unchanged in its modelling. Parties were eager to suggest changes that would alleviate or mitigate the impacts that LEI identified. However, the Commission emphasizes that LEI's scope was intentional. The Commission recognizes that in addition to the AUC's inquiry, the government directed both the AESO and the MSA to consider potential changes to the market, while also consulting on policy changes itself. As such, the Commission recognized that any work it conducted on potential changes was not only outside the scope of its mandate but would be duplicative of other work. As such, the Commission chose to focus its inquiry on the current framework.

**Observation: Under the current market design, increased renewables will exacerbate supply adequacy issues.**

35. To better understand the impact of renewables on supply adequacy, LEI also developed cases with additional renewable generation. Its More Renewables cases included an additional 2,100 MW in the near term and an additional 2,400 MW in the longer term (2034-2040). The additional renewables decreased pool prices resulting in existing dispatchable generation being more likely to retire and new dispatchable generation less likely to enter the market. As shown in Figure 2, this exacerbated supply adequacy issues, resulting in higher levels of expected unserved energy.

**Figure 2. Expected unserved energy under base cases vs More Renewables Calibrated cases for 2038**[12]




36. Some parties indicated that LEI's More Renewables cases are not realistic. They submitted that the cases add immature projects that are unlikely to all be constructed, that current levels of transmission congestion are likely to delay some renewable additions, and that since additional renewables will depress the price that renewables receive, that it will become more difficult to finance new renewable projects. The Commission accepts that the level of renewable integration in LEI's More Renewables cases is unlikely to occur at the rate modelled. Nonetheless, the Commission finds it to be a helpful illustration of the directional impacts of additional renewables.

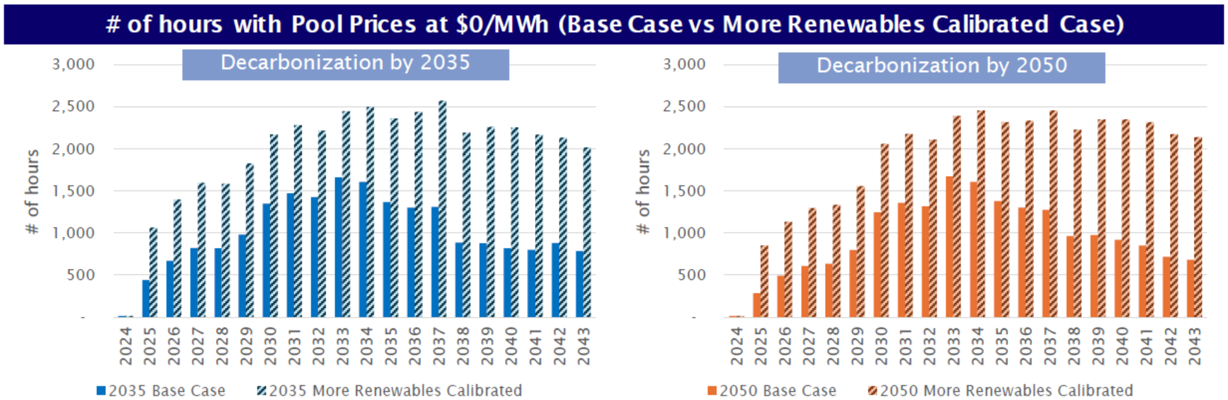
**Observation: Renewables lower pool prices and increase volatility, reducing the signal for dispatchable generation to enter the market.**

37. The LEI Report finds that the current energy-only market design does not provide sufficient economic incentives to ensure adequacy of supply in all hours. Growing levels of renewable generation result in lower pool prices, which dampens the investment signal for dispatchable generation.

38. Increased renewables lead to a greater frequency of zero-priced hours, as shown in Figure 3.

[12] Exhibit 28542-X0049.01, Expert Report - London Economics International - Cover Report, PDF page 18.

**Figure 3. Number of hours with pool prices at zero under normal weather conditions**[13]




39. Increased zero-priced hours, and lower pool prices generally, reduces the profitability of thermal generators, with existing thermal generators becoming more likely to retire and new thermal generators less likely to enter the market. With less dispatchable generation, there is greater potential for supply adequacy shortfalls.

40. LEI's model tracks the revenues earned and costs incurred by generation assets in the energy market, comparing the forecasted net profits of the generation assets against the capital costs. The results confirm the findings of the AESO's preliminary 2024 Long-term Outlook (LTO) that additional investment cannot be supported by the forecast market prices. In addition, LEI's modelling shows that under the forecast conditions, dispatchable new generation is generally not earning a robust return on investment until the late 2030s.

41. Parties raised concerns that LEI's modelling had overly relied on the AESO's LTO. Stakeholders identified the draft nature of the LTO and submitted that LEI failed to question the AESO's assumptions.

**Observation: Newer low-carbon technologies could be considered first-of-a-kind and have a greater level of associated risk, particularly under a target to decarbonize by 2035.**

42. Parties commented that the LTO's inclusion of new generation technologies such as hydrogen-based generation, carbon capture and storage technology, and small modular nuclear reactors pose significant risks as the timing and costs of those technologies are uncertain. LEI's analysis indicates that even with the currently assumed costs, hydrogen-based generation and natural gas with carbon capture and storage would under earn in the first 10 years of the forecast period. The Commission acknowledges that these newer technologies are not yet commercially proven in power generation applications and have a greater level of risk associated with them, which is particularly acute under a target to decarbonize by 2035.

43. Other parties submitted that the AESO has historically been overly cautious in its forecasting and has failed to accurately predict how quickly new technologies may be adopted. In particular, parties focused on the potential for energy storage to play a significant role in mitigating impacts to supply adequacy. They submitted that while the AESO's LTO contains

[13] Exhibit 28542-X0049.01, Expert Report - London Economics International - Cover Report, PDF page 17.

approximately 500 MW of battery storage, there is 7,000 MW of proposed storage currently in the AESO's connection process. Parties identified that storage could be used to transfer energy from periods of supply surplus, where renewables may be curtailed, to times of supply shortage. They identified that storage would be able to take advantage of the price volatility shown in the LEI Report, which indicated an increase in the number of hours with $0/MWh prices and hours with prices greater than $500/MWh.

**Observation: Energy storage can play a role in reducing supply adequacy issues but is not a complete solution and is not expected to be economic under the current energy market and AESO tariff.**

44. The Commission notes that the LEI Report finds that under the current market design, additional storage would generally not be profitable based on energy market revenues and that storage would rely on revenues from the ancillary services markets.[14] The Commission accepts that storage has the potential to play a significant role in mitigating issues related to supply adequacy, however, for the benefits of storage to materialize, changes to the current market design and framework will likely be required. Stakeholders identified increasing the price cap, decreasing the price floor and creation of a storage-specific tariff as potential means to incentivize storage development.

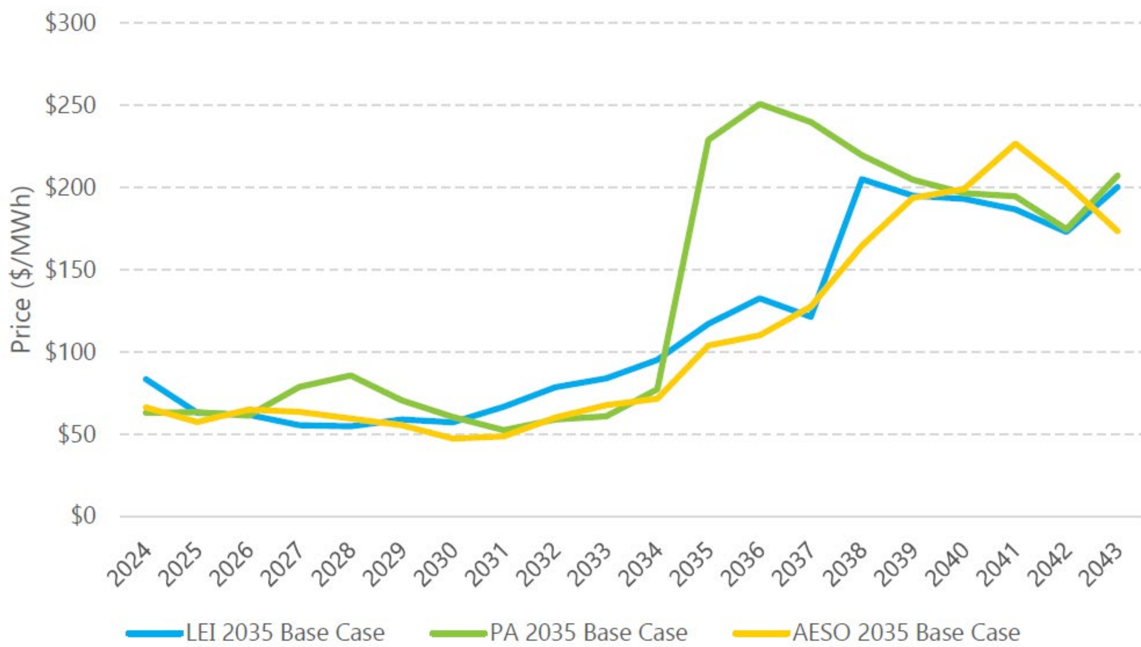
45. The Commission also recognizes that the LEI Report forecasts the potential for extreme supply adequacy events that could last up to 23 hours; currently, the most economic forms of energy storage are short term (approximately four hours in duration) and would not, on their own, be able to resolve these types of events. As such, the Commission cautions that storage is not a complete solution to the forecasted supply adequacy issues.

**Observation: Given the scale of expected unserved energy, minor changes to supply mix assumptions do not alleviate supply adequacy concerns.**

46. The Renewable Generators Alliance retained Power Advisory to prepare models responding to the LEI Report. Power Advisory first modelled the system using the same assumptions as LEI and the AESO and found that the results were largely in line with those of LEI and the AESO. One notable difference is that Power Advisory's model has significantly higher prices in its 2035 base case between 2035 and 2038.

[14] Exhibit 28542-X0050, Expert Report - London Economics International - Annex 1 - Scenario Analysis, PDF pages 33 and 34.

**Figure 4. Power Advisory 2035 base cases average annual pool price**[15]




47. Power Advisory then modelled five different scenarios in which it added: (1) incremental gas generation, (2) incremental energy storage, (3) incremental wind and solar generation, (4) incremental gas generation and incremental energy storage and (5) incremental wind and solar generation and incremental energy storage. The different scenarios had varying degrees of impacts but generally resulted in both lower levels of expected unserved energy and lower pool prices. The hybrid scenario with incremental gas generation and incremental energy storage, in which Power Advisory included an additional 330 MW of gas generation, 795 MW of long-term (pumped hydro and compressed air) storage and 180 MW of short-term (battery) energy storage, was the most effective at reducing expected unserved energy.

48. However, it is unclear to the Commission if the additional assets that Power Advisory included would be economic. The additional generation contrasts with LEI's findings that dispatchable generation is not earning a robust rate of return until the late 2030s. There is no analysis of the costs of the long-term energy storage in Power Advisory's report. Further, the ability to add incremental generation may be reliant on the increased prices in Power Advisory's base case between 2035 and 2038. Power Advisory stated that, in accordance with the draft *Clean Electricity Regulations*, it restricted fossil fuel assets to run no more than 450 hours in a year after 2035, whereas the AESO and LEI appeared to exempt coal-to-gas units from this restriction until their retirement in 2037. Power Advisory stated it was not aware of such an exemption, and thus their model restricts those units, resulting in higher prices.

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[15] Exhibit 28542-X0088, Renewable Generators Alliance - Attachment - Expert Report of Power Advisory LLC, PDF page 8.

49. The Commission understands that the AESO and LEI’s exemption of coal-to-gas units is consistent with the current draft of the *Clean Electricity Regulations.* Annex 1 of the draft *Clean Electricity Regulations* states:

> A unit that ceased burning coal and has been "significantly modified": **Starting on the latter** of January 1, 2035, or January 1st of the year after its life extension under the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*, the proposed performance standard would apply. [emphasis added]

50. Because the regulations state that the performance standards could potentially start on a later date than January 1, 2035, the Commission considers that some coal-to-gas units may be able to run for more than 450 hours beyond 2035 and, as such, places greater weight on the price forecasts in the LEI Report relative to the Power Advisory Report.

51. Most importantly, Power Advisory’s scenarios do not completely eliminate expected unserved energy. Expected unserved energy under the hybrid gas and storage scenario was still 2,049 MWh in 2038; above the AESO’s resource adequacy threshold of 1,135 MWh. The Commission observes that even this smaller amount would be an unprecedented amount of load being shed and the Commission considers it would not be acceptable to Albertans in any category of consumer.

52. Overall, the Commission recognizes that the scenarios identified in the AESO’s LTO, and therefore modelled in LEI’s analysis, are unlikely to occur exactly as forecast. Ultimately, the retirement of existing assets and construction of new generation will be determined by the market, including commercial incentives in contracts. However, the Commission is satisfied that the scenarios provide relative and directional guidance on issues that may arise under the existing market design. Several parties agreed with LEI’s results and confirmed they are consistent with their own modelling. Further, Power Advisory’s analysis provides important evidence that even with different assumptions around supply mix, supply adequacy remains an issue.

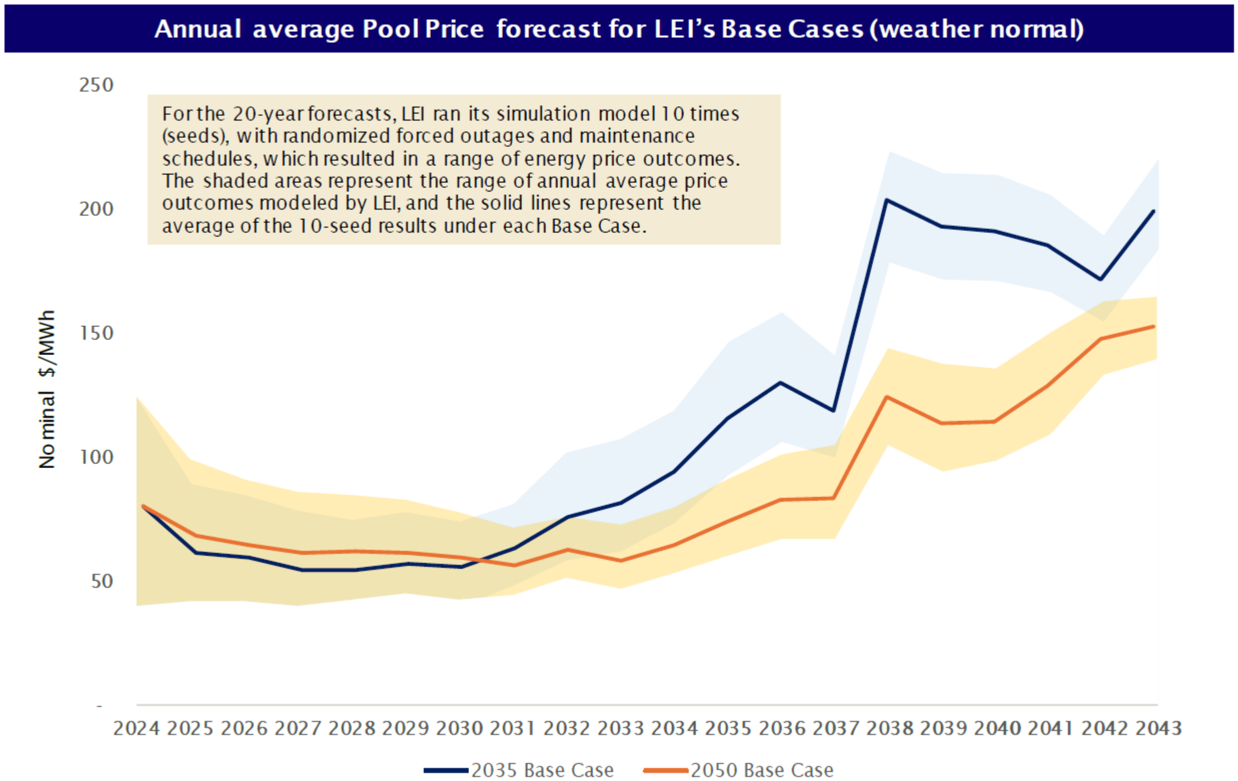
# 4 Affordability

53. LEI’s forward-looking analysis was also used to analyze the future cost of electricity.

**Observation: Under the current market design, pool prices are initially stable, but are then expected to increase at a rate above inflation in the 2030s. An increased rate of decarbonization, i.e., net zero by 2035 instead of by 2050, will exacerbate affordability issues.**

54. In the short term, the LEI Report shows prices declining from the recent high levels; this is a result of the more than 2,000 MW of natural gas generation anticipated to come online in 2024. The LEI Report finds that pool prices will increase sharply in the late 2030s. It states that this increase is primarily driven by two factors: carbon costs and reliability events. The report also identifies that pool prices will become more volatile over time. While increased renewables will result in an increase in the number of zero-priced hours, a tightening capacity reserve margin will result in more frequent price spikes. As shown below, the LEI Report finds that affordability, based on pool prices, is expected to be worse under the 2035 Base Case than the 2050 Base Case.

**Figure 5. Comparison of pool price forecast under 2035 and 2050 base cases**[16]

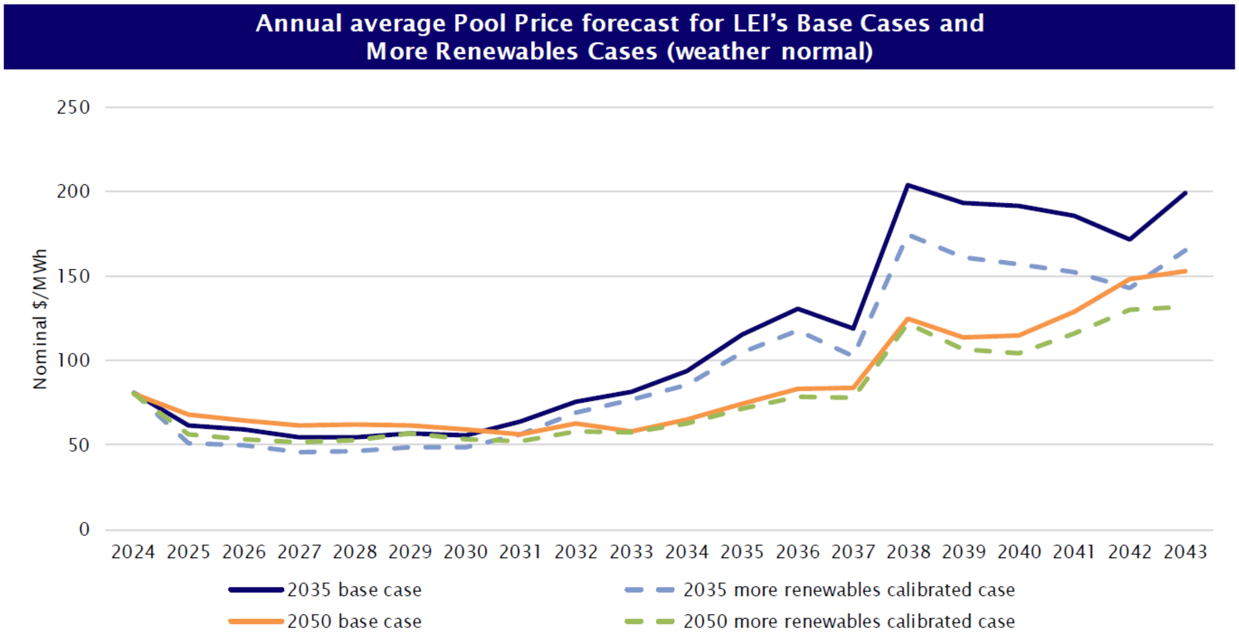



55. The LEI Report finds that residential electric bills are expected to increase at a rate greater than inflation in the later years of the forecast period. Under the 2035 Base Case, residential electric bills are expected to increase at a province-wide average compound annual growth rate of 1.9 per cent per year from 2025 to 2030 and then a much higher rate of 6.8 per cent per year from 2030 to 2040. Under the 2050 Base Case, residential electric bills increase by a compound annual growth rate of 1.6 per cent per year from 2025 to 2030 and 4.3 per cent per year from 2030 to 2040. These increases are primarily driven by the increase in pool prices rather than costs associated with transmission and distribution. Despite these higher prices, as mentioned above, consumers face a lower level of service reliability.

56. Wind and solar generally offer their energy in the market at $0/MWh. As previously discussed, LEI developed cases with additional renewable generation. As shown below, the LEI Report finds that the increased renewables cases decrease pool prices.

[16] Exhibit 28542-X0088, Renewable Generators Alliance - Attachment - Expert Report of Power Advisory LLC, PDF page 19.

**Figure 6. Pool prices assuming more renewable capacity**[17]




57. Residential bills also decreased with additional renewable generation. For example, under LEI's 2035 More Renewables Calibrated Case, residential bills had a province-wide compound annual growth rate of 3.7 per cent, down from 4.2 per cent under the 2035 Base Case. The LEI Report showed that the estimated $1.9 billion in additional transmission costs that would be needed to integrate the additional renewables would be more than offset by the decrease in pool prices.

58. Several parties supported LEI's conclusion that renewables assist with affordability and emphasized that the growth of renewables has benefited the provincial economy.

59. Some parties submitted that LEI's affordability analysis is primarily focused on residential bills, with no analysis of costs to commercial or industrial consumers. Industrial customers highlighted that transmission costs are a significant concern. They submitted the importance of changes to policies and regulations that would enable the principle of cost causation to be reflected in transmission tariffs to ensure fair and equitable cost recovery of transmission infrastructure.

60. Currently in Alberta, with few exceptions, load pays for the costs of transmission infrastructure. However, the Commission recognizes that the transition to a net-zero electric sector will continue to drive transmission costs that are not being caused by load. The AESO's most recent Long-Term Plan identifies several major transmission projects required to integrate additional renewable generation onto the system. As such, generators, rather than load, may be in the best position to make decisions that would mitigate transmission costs. However, there is

17 Exhibit 28542-X0088, Renewable Generators Alliance - Attachment - Expert Report of Power Advisory LLC, PDF page 20.

currently little incentive and, in the Commission's view, insufficient locational signals to lead generators to make such decisions.

61. The LEI Report includes an illustrative analysis comparing the cost of acquiring electricity from the grid as opposed to installing an off-grid solution, i.e., a combined cycle gas turbine with peaker backup, for a large industrial consumer. It shows that under the 2035 Base Case, an off-grid solution will have lower levelized costs than acquiring electricity from the grid. Under the 2050 Base Case, an off-grid solution is lower in the early years but grid services would have a lower cost beyond 2031.

62. The Commission recognizes that the Minister of Affordability and Utilities has already communicated that changes to the allocation of transmission costs should be expected.[18]

## 5 Role of demand response

**Observation: Demand response has some potential to mitigate supply adequacy impacts and reduce future costs to electricity consumers.**

**AUC Commitment: The Commission will explore demand response opportunities, including exploring time varying rates as a priority item in the near term.**

63. Many parties identified that demand response could play a role in mitigating both supply adequacy and affordability issues. Parties indicated that the identified issues highlighted the need for policies that provide consumers with enhanced choice and flexibility in managing their electricity costs. They stated there is a need for improved price signals for load to respond to reliability events and to optimize the transmission and distribution systems. Parties also identified time-of-use rates as a method used in other jurisdictions that could result in significant savings.

64. While LEI did not explicitly study demand response, it did study the impacts of decreased demand in single years. These "demand-shock" scenarios, where supply mix was held constant, showed significant decreases to costs and supply adequacy events in response to decreased demands.

65. Under the 2035 Base Case, a 3.5 per cent decrease in demand, decreased annual average pool prices by 15 to 18 per cent. Under the 2050 Base Case, a similar demand decrease resulted in annual average pool prices decreasing by 13 to 16 per cent.

66. Further, the LEI Report estimated that if the supply mix were held constant, between 850 to 1,200 MW of additional dispatchable demand-side resources by 2038 could reduce unserved energy events to levels within the AESO's resource adequacy threshold.

[18] Policy Guidance to the Alberta Utilities Commission, February 28, 2024. https://www.alberta.ca/system/files/au-minister-neudorf-letter-to-auc-20240228.pdf

## 6 Stakeholder perception of the Alberta power market

67. The AUC retained FGS Longview to conduct a market perception study to review the attractiveness of Alberta's power market from an investor perspective and identify the drivers behind changes in stakeholder perceptions. The report is representative of some viewpoints but should not be taken as a comprehensive scan of all stakeholder perceptions.

**Observation: Investors are concerned about the current level of policy uncertainty.**

68. The FGS Longview's Report[19] indicates that stakeholder perception of Alberta's power market is highly varied and changing rapidly. However, the report highlights that policy uncertainty stands out as a key factor of changing stakeholder perception among all participant groups. It states that "[p]olicy uncertainty is leading to a reduction in appetite for investment from both incumbent and non-incumbent generators as well as from providers of capital." This uncertainty has increased over the past decade, which is preventing investors from being able to accurately project future market and policy environments, and accordingly, model project revenues.

69. The FGS Longview Report states that most participants indicated that their primary concerns were short term, stemming from the unfinalized *Clean Electricity Regulations*, the provincial pause on renewables and other policy proposals being considered at the federal and provincial levels.

70. The FGS Longview Report found that participants generally agreed "that the existing energy-only model is well positioned to deliver on concurrent goals of emissions reduction and affordability, but many participants indicated that the existing market framework was not set up to deliver on reliability."

## 7 Conclusion

**Observation: By the late 2030s, under the existing market framework, consumers would be paying significantly higher rates for electricity, while receiving a substantially lower level of reliability. Given this, changes to the energy market and policy framework are necessary.**

71. The transition to a net-zero electricity sector must balance decarbonization with affordability and reliability. The large amount of expected unserved energy and the steep rise in residential bills in the 2030s shown by the LEI Report demonstrate that higher levels of renewables will have significant impacts on reliability and affordability under the existing market design. The forecast amount of expected unserved energy far exceeds what Albertans have experienced historically. This is not an acceptable outcome, particularly given the higher rates that consumers would be paying for electricity.

[19] Exhibit 28542-X0047, Expert Report - FGS Longview - Market Perception Study.

72. On March 11, 2024, the Minister of Affordability and Utilities directed the AESO to work with industry and stakeholders to design a restructured energy market. As the adjudicator of changes to the AESO market rules, the Commission takes no current position on what specific market changes are required. However, the Commission finds that the current market is not sustainable in the long term.

73. Changes to the energy market were outside the scope of LEI's analysis, however, it asserted that the reliability events and large price increases identified could be averted with balanced and thoughtful modifications to the current market design. Many stakeholders supported this statement and expressed support for a continued energy-only market. The FGS Longview Report similarly found that most participants preferred maintaining the energy-only market, with minor revisions to address reliability issues.

74. Parties also emphasized the importance of consultation when considering any changes to the market. The Commission anticipates the AESO, acting on stated government policy advice, to immediately begin the consultation process to implement changes to the market in a timely manner.

Dated on March 28, 2024.

**Alberta Utilities Commission**

Carolyn Dahl Rees
Chair

Michael Arthur
Commission Member

# Appendix 1 – Order-in Council 171/2023

(return to text)

Appendix_1_Order-in
-council 2023-171.pdf

(consists of 3 pages)

## Appendix 2 - London Economics International LLC expert report

Appendix 2__LEI_AUC Renewables Inquiry C(

(consists of 24 pages)

Appendix 2_LEI_Annex 1 - Scena

(consists of 49 pages)

Appendix 2_LEI_Annex 2 - Projec

(consists of 31 pages)

Appendix 2_LEI_Annex 3 - Proba

(consists of 26 pages)

# Appendix 3 – FGS Longview expert report

Appendix
3_Market-Perception-:

(consists of 24 pages)

O.C. 171/2023

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*Province of Alberta*
Order in Council

# ORDER IN COUNCIL

Approved and ordered:

Shakhari

Lieutenant Governor
or
Administrator

The Lieutenant Governor in Council

(a) orders the Alberta Utilities Commission to inquire into and report to the Minister of Affordability and Utilities on the ongoing economic, orderly and efficient development and operation, in the public interest, of electricity generation in Alberta, in accordance with the terms of reference in the attached Schedule,

and

(b) determines that the Alberta Utilities Commission has the same power with respect to ordering by whom and to whom its costs and other costs of, or incidental to, the inquiry described in clause (a) are to be paid as the Commission has with respect to its hearings and other proceedings.

CHAIR

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For Information only

Recommended by: Minister of Affordability and Utilities

Authority: Alberta Utilities Commission Act (section 8)

# SCHEDULE

## Terms of Reference for an Inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta

WHEREAS the Government of Alberta recognizes that the development of new renewable electricity will play an important role in the province's sustainable energy future;

WHEREAS the growth in new renewable electricity and other distribution connected generation in Alberta have materially increased;

WHEREAS the anticipated growth of renewable electricity developments is expected to have impacts on lands and the reliability of the Alberta Interconnected Electricity System;

WHEREAS in anticipation of continued growth in new renewable electricity, the Government of Alberta is concerned about impacts to lands used for agricultural purposes and high value environmental land such as native prairie, mountains and wetlands, and to the impact on Alberta's pristine viewscapes;

WHEREAS in anticipation of continued growth in new renewable electricity, the Government of Alberta is concerned about reclamation of agricultural and high value environmental lands;

WHEREAS in anticipation of continued growth in new renewable electricity, the Government of Alberta is concerned about the impact to Alberta's generation supply mix and electricity system reliability;

WHEREAS new renewable electricity developments may be proposed on Crown land;

**THEREFORE,** the following terms of reference apply in respect of the inquiry into and report to the Minister of Affordability and Utilities on the ongoing economic, orderly and efficient development of electricity generation in Alberta:

1. The Alberta Utilities Commission (AUC) shall inquire into the following matters for the purposes of gathering and providing information to government:
    a. Considerations on development of power plants on specific types or classes of agricultural or environmental land;
    b. Considerations of the impact of power plant development on Alberta's pristine viewscapes;
    c. Considerations of implementing mandatory reclamation security requirements for power plants;
    d. Considerations for development of power plants on lands held by the Crown in Right of Alberta;
    e. Considerations of the impact the increasing growth of renewables has to both generation supply mix and electricity system reliability.

2. In conducting the inquiry, the AUC shall hear from interested parties.

3. The AUC’s report:
    a. shall make findings or provide observations or considerations for options, as it deems appropriate, based on its analysis of the evidence received during the inquiry and in accordance with these terms of reference;
    b. shall be submitted to the Minister of Affordability and Utilities no later than March 29, 2024.

# Module B Study:

# Overview of Modeling Results and Key Findings

*prepared for the Alberta Utilities Commission ("AUC")*

*in Proceeding 28542: AUC Inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta*

February 7, 2024

LONDON ECONOMICS

**London Economics International LLC**
www.londoneconomics.com

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# Table of figures

# 1 Executive summary

### In August 2023, the Alberta Government initiated an Inquiry into the impact of renewable generation on the reliability and affordability of electricity in Alberta

The Government of Alberta directed the Alberta Utilities Commission ("AUC") to launch an Inquiry into the impact of the growing level of renewable energy on the Alberta electricity system.[1] Specifically, the AUC was directed to examine changes in the generation supply mix, system reliability, and customer affordability as a result of the growth of renewable generation in the Alberta electricity market.[2]

London Economics International LLC ("LEI"), a global economic, financial, and strategic advisor in energy, water, and infrastructure, was hired to conduct a forward-looking analysis, in the context of the province's current wholesale market design and policy environment and leveraging data and analysis from the Alberta Electric System Operator ("AESO"). The forward-looking analysis began with two Base Case outlooks for the Alberta electricity sector over the next 20 years – one Base Case was designed to reflect federal draft Clean Electricity Regulations ("CER"),[3] referred to as the 2035 Base Case; the other Base Case is consistent with the province's Alberta Emissions Reduction and Energy Development Plan,[4] referred to as the 2050 Base Case. These Base Cases represent two different decarbonization policy pathways for the Alberta electricity sector – decarbonization by 2035 versus decarbonization by 2050. Additional scenarios were also analyzed layered on top of these two Base Cases – to test the impact of even more renewables (the More Renewables Cases) and to test the impact of demand shocks (the Lower Demand Cases). This report summarizes the results of that analysis.

More detail on the origins of this analysis can be found in Section 2.

### Mandatory and voluntary efforts to decarbonize are impacting the Alberta electricity sector

Alberta has a real-time energy-only electricity market. Inherent in this electricity market design is the fact that the signal to attract further investments in generation lies entirely in investor expectations for energy prices (referred to as "Pool Prices" throughout this report). Furthermore, Alberta's existing electricity market framework does not mandate a specific quantity of new investment on a going forward basis or any system reliability requirements. The quantity and type of investment in new generation assets are ultimately determined by whatever market forces

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[1] Government of Alberta. *Order in Council 171/2023.* August 2, 2023.

[2] After the Alberta government issued the order-in-council establishing the terms of reference for the Inquiry, the Ministry of Affordability and Utilities issued a press release and fact sheet that emphasized the government's interest in considering both affordability and reliability impacts to the grid from additional intermittent power sources. *See* Alberta Ministry of Affordability and Utilities. *AUC approvals pause for renewable projects: Minister Neudorf.* August 25, 2023.

[3] Government of Canada. *Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations.* August 19, 2023.

[4] Government of Alberta. *Alberta emissions reduction and energy development plan.* April 2023 (updated January 2024).

can support. LEI conducted its forward-looking analysis and modeling based on this Alberta-specific market context and design.

Alberta, like many other jurisdictions around the world, is contending with the impact on its electricity market of external developments driven by government, business, and consumer commitments to decarbonizing the economy. The federal draft CER requires all electricity generation that falls under the CER requirements to be net zero by 2035, which would compel all fossil-fuel fired power plants to retrofit with carbon capture technology or face significant operational restrictions.

At the same time, due to corporate Environmental, Social, and Governance ("ESG") commitments, the presence of a functioning competitive electricity market, and Alberta's reputation as a relatively easy place to develop new generation projects, a large amount of new renewable energy projects have been built in recent years and continue to be planned. The construction of these projects does not depend solely on revenues from the Alberta wholesale electricity market. These dynamics are creating unique challenges in Alberta due to the small size of its electricity system, its energy-only electricity market design, and the lack of any reliability mandate as part of its electricity market.

More details on the Alberta market context can be found in Section 3.

### LEI used simulation modeling to dynamically assess market outcomes over the next 20 years

LEI used its proprietary simulation-based modeling tools to analyze the impact of renewable energy generation on the reliability and affordability of Alberta's electricity system over the next 20 years. Simulation modeling is required because we cannot simply assume that supply and demand remain the same. Our modeling suite allows us to assess how different generation technologies perform operationally and economically in the market, and dynamically integrate those considerations to determine the future evolution of electricity supply.

This analysis is adapted to Alberta's specific and unique characteristics. LEI's wholesale market analysis includes strategic bidding to assess the impact of economic withholding. LEI considered external drivers to develop a variety of reasonable scenarios. LEI also analyzed the impacts of different weather conditions and generation outage patterns to understand the prospect for system reliability – supply adequacy – with the evolving supply mix.

Outcomes from LEI's wholesale energy modeling are also used to project total electric bills for a typical residential customer in Alberta, to assess the impact of increased renewables on affordability. We paired the outlook for the cost of electricity supply under each scenario with the likely evolution of transmission and distribution system costs to develop an estimate of total electric bills.

More details on the modeling methodology and assumptions can be found in Section 4.

## Key findings

**The electric grid will become less reliable: by the late 2030s, there is potential for unprecedented load shed in Alberta under the current electricity market design, regardless of the specific decarbonization policy pathway, because of insufficient supply**

**The current energy-only market design does not provide sufficient economic incentives to ensure electric system reliability in Alberta under the modeled conditions**

**Growing levels of renewable generation result in lower Pool Prices, dampening the investment signal under the current market design and causing system reliability to decline**

Under all scenarios modeled, Alberta's electric system reliability performance worsens over the longer term. This result is based on the continuation of the current energy-only market design and associated policies, as well as implementation of decarbonization policies. Severe supply adequacy problems start to emerge in the mid-2030s. By the late 2030s, reliability risk under the 2035 Base Case is expected to be worse than the 2050 Base Case – although under both Base Cases, the level of reliability by the late 2030s would be materially worse than the level Albertans have been accustomed to. In the 5% most severe reliability events, nearly 10% of demand would not be met, with unserved load events that last for almost an entire day (23 hours). Supply adequacy problems emerge even sooner (in the next five years) if low Pool Prices motivate significant retirements of coal-to-gas units in the short term, without sufficient incremental new dispatchable resources (i.e., generation that can be effectively turned on when needed).

It is important to keep in mind that the forward-looking analysis is subject to technological risk. LEI's analysis relies on AESO's preliminary 2024 Long Term Outlook ("LTO") supply mix assumptions, which incorporate new generation technologies including hydrogen-based generation, carbon capture technology, and in the very long term, the installation of small modular nuclear reactors. LEI took these assumptions as a given and did not model the possibility of delays in construction or higher costs to construct, nor the possibility that these technologies would operate in a different way than currently expected. Although unquantified, these risks would put further pressure on supply adequacy and system reliability.

Furthermore, LEI finds that additional renewables exacerbate Alberta's electricity reliability problems around supply adequacy because they result in lower Pool Prices, which deteriorates the earnings of and dampens investment signals for other supply resources under the current market design.

More details on findings related to reliability can be found in Section 5.

**Average Pool Prices will increase sharply in the late 2030s: Pool Price trends are driven by carbon policies and the costs of reliability events**

Pool Prices rise over the 2024-2043 time horizon, driven by carbon costs as well as the cost of reliability events. At the top end, Pool Prices are estimated to grow from an average of \$81/MWh in 2024 to \$200/MWh by 2043 under the 2035 Base Case. The 2035 Base Case sees higher price increases than the 2050 Base Case due to the draft CER's stricter rules and accelerated net zero implementation timeframe. Additional renewables moderate these price increases but worsen supply adequacy.

More details related to findings on Pool Prices can be found in Section 6.

**Residential customer electric bills are expected to outpace inflation in the later years of the forecast period, at a similar trajectory to forecasted Pool Prices**

**Despite higher electric bills, there is worsening service reliability as compared to today**

Under all scenarios, residential electric bills are expected to increase much faster than inflation in the later years of the forecast period, largely driven by the increase in Pool Prices. Importantly, customers not only face these higher bills, but also receive a lower level of service reliability than they are accustomed to. However, such outcomes assume a continuation of the status quo – the current energy-only electricity market design and associated policies. Although outside the scope of LEI's study, we believe these outcomes could be averted with balanced and thoughtful modifications to the current electricity market design.

Additional renewables moderate electric bill increases through a decrease in Pool Prices, although those scenarios also require more transmission investment, muting the overall impact.

More details related to findings on residential customer bills can be found in Section 7.

### Roadmap to more detailed information

This document is a high-level summary of LEI's analysis. LEI has compiled three Annexes that provide more detail on the modeling approach, the different scenarios analyzed, key underlying assumptions and inputs, and detailed modeling results and findings. A list of these Annexes is provided in Section 8.

# 2 AUC Renewables Inquiry and LEI's scope of work

## 2.1 AUC Inquiry to assess the impact of renewables on reliability and affordability

On August 2, 2023, the Government of Alberta issued a new regulation temporarily pausing approvals under Section 9 or 11 of the Hydro and Electric Energy Act in respect of a hydro development or power plant that produces renewable electricity.[5] Simultaneously, the Government of Alberta asked the AUC to conduct a public inquiry (the "Renewables Inquiry") and issue a report no later than March 29, 2024; the terms of reference for this Renewables Inquiry include a "*consideration of the impact the increasing growth of renewables has to both generation supply mix and electricity system reliability*" – this is the initial focus of LEI's study.[6]

On August 25, 2023, Minister Neudorf issued a press release and fact sheet on the Renewables Inquiry and Related Pause that emphasized the Government of Alberta's concern with both affordability and reliability impacts to the grid from additional intermittent power sources.[7] Thus, affordability became another focus of LEI's study.

The Inquiry terms of reference and the additional context from the Minister of Affordability and Utilities guided LEI's scope of work.

## 2.2 LEI's scope: analysis to focus on existing market design, leveraging AESO analysis

The AUC and LEI agreed to examine the Inquiry topics through the lens of Alberta's current energy-only electricity market design and existing policy framework.[8] Market design issues were outside the scope of LEI's study. As a result, LEI's modeling and analysis assumed the following:

- Market design consists of a single clearing price real-time energy-only market with simple price/quantity offers;[9]
- Pool Prices that are above marginal costs continue to be permitted, in order to provide an investment signal under the current market design;
- Real-time energy price is limited to a $0/MWh floor and $1,000/MWh cap;
- No day-ahead unit commitment; no start-up cost recovery guarantees; and
- The existing Transmission Regulation policy is maintained, such that LEI's modeling assumes an uncongested transmission system and continues to use a single clearing price for all generation producing energy in a given hour.

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[5] Government of Alberta. *Order in Council 172/2023.* August 2, 2023.

[6] Government of Alberta. *Order in Council 171/2023.* August 2, 2023.

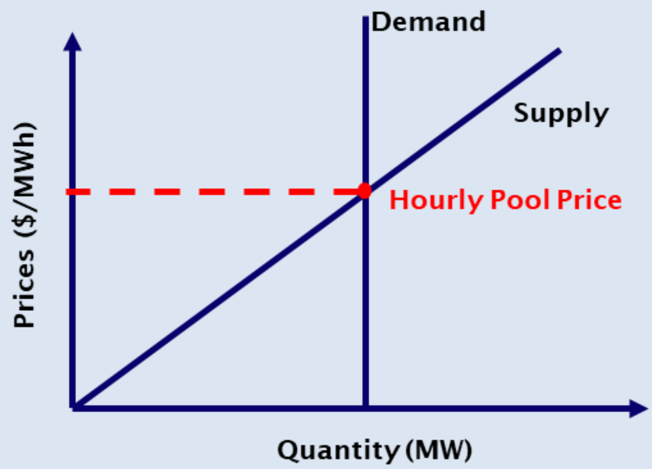
[7] Alberta Ministry of Affordability and Utilities. *AUC approvals pause for renewable projects: Minister Neudorf.* August 25, 2023.

[8] AUC. *Expert reports – scope of work (Exhibit 28542-X0004).* October 24, 2023.

[9] Ancillary services are procured separately through sequential auctions held day-ahead on the NGX platform.

*How are hourly Pool Prices set in Alberta?*

The Alberta wholesale market for electricity is a single-price, competitive energy market, in which market outcomes (e.g., price and dispatch of power plants) are determined by the intersection of demand and supply, subject to certain limitations, such as the price floor at $0/MWh and $1,000/MWh price cap. Generators offer to produce energy at a certain price. The generators' offers are the supply curve in the illustration below, while the vertical line reflects the electricity load on the grid that must be met (the demand). AESO, as the system operator, determines the most economic (least cost) dispatch of generators, based on their offers. This happens on a minute-by-minute basis, as demand and supply are constantly changing. The hourly average of the minute-by-minute prices is known as the hourly Pool Price. Generators that are producing electricity within a specific hourly interval get paid the Pool Price and buyers of electricity must pay the Pool Price.




In addition, the AUC requested that LEI leverage research and analysis conducted by the AESO. LEI used the AESO's load forecast, retirement schedule, and generation supply assumptions from its preliminary 2024 LTO released on November 15, 2023.[10] The AESO's preliminary 2024 LTO provided the first set of scenarios for LEI's analysis, representing two different decarbonization policy pathways:

- 2035 Base Case, which assumes compliance with the federal draft CER;[11] and
- 2050 Base Case, which is aligned with the province's Alberta Emissions Reduction and Energy Development Plan.[12]

LEI also developed additional scenarios to consider the impact of increasing renewables over time, and of demand shocks (i.e., unexpected changes in demand) that result in lower demand, as summarized in Figure 1 below.

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[10] AESO. *Forecasting Insights.*

[11] Government of Canada. *Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations.* August 19, 2023.

[12] Government of Alberta. *Alberta emissions reduction and energy development plan.* April 2023 (updated January 2024).

**Figure 1. Overview of scenarios in LEI analysis**

| Different decarbonization policy pathways to net zero | Impact of increasing renewables | Impact of demand shocks |
| --- | --- | --- |
| **2035 Base Case** *(Federal draft CER)* | **2035 More Renewables Calibrated Case** *(Federal draft CER with more renewables)* | **2035 ~390 MW Lower Demand Case**<br>**2035 ~800 MW Lower Demand Case**<br>*(Federal draft CER with 3.5% and 7.2% lower demand, respectively)* |
| **2050 Base Case** *(Provincial plan)* | **2050 More Renewables Calibrated Case** *(Provincial plan with more renewables)* | **2050 ~390 MW Lower Demand Case**<br>**2050 ~800 MW Lower Demand Case**<br>*(Provincial plan with 3.5% and 7.2% lower demand, respectively)* |
| | The More Renewables Cases introduce 4,520 MW of additional renewables (relative to the Base Cases) over the forecast period | |

Specifically, the More Renewables Calibrated Cases reflect two key considerations – first, the impact of additional renewables on market outcomes (i.e., lower Pool Prices), and second, the impact of those lower Pool Prices on other supply resources. Through financial analysis of modeled market outcomes, LEI found that the Alberta energy-only market would not be able to sustain as many non-renewable resources under the More Renewables Calibrated Cases as compared to the Base Cases. LEI also tested different weather profiles to assess supply adequacy. Assessing other dimensions of system reliability was out of scope for this analysis.

Details on the different scenarios and their underlying assumptions are available in Annex 1 *(Scenario Analysis: Long Term Weather-Normal Energy Market Forecast)*.

# 3 Mandatory and voluntary efforts to decarbonize are impacting market outcomes

Many electricity markets around the world are starting to adjust to government policies to decarbonize the economy, which includes reducing emissions from electricity sector generation as well as electrifying buildings and transportation. Alberta is no different.

The federal government issued its draft CER in August 2023,[13] which requires electricity generation that meets the CER applicability criteria to be "net zero" by 2035. According to the draft CER, the proposed regulations apply to all electricity generating units that:

a) have an electricity generation capacity of 25 MW or more;
b) generate electricity using fossil fuel; and
c) are connected to an electricity system that is subject to North American Electric Reliability Corporation ("NERC") standards.

These physically binding requirements would require any fossil fuel-fired facilities to retrofit using carbon capture technology or face significant operational restrictions.[14] Given that the province of Alberta has already negotiated the retirement or conversion of coal-fired facilities (with the last remaining coal facility slated for conversion to gas this year), the draft CER would mainly impact gas-fired generation. Currently, gas-fired generation represents over 59% of total capacity, and in recent years has produced 64% of annual energy transmitted on the Alberta Interconnected Electric System ("AIES").[15]

Concurrently, the province has experienced a large buildout of renewable energy capacity, as shown in Figure 2 below, driven in large part by the ease of building and operating merchant generation in Alberta, as well as the corporate interest in meeting ESG commitments. Many of these projects are not wholly dependent on revenues from Alberta's energy market. As a result, more than 6,000 MW of renewable capacity has been installed in Alberta since 2000, with another 3,395 MW under construction, 3,588 MW with regulatory approval from the AUC, and another 30,250 MW of projects that have either been announced, applied for connection to the AESO, and/or applied for regulatory approval, according to AESO's November 2023 Long-term Adequacy ("LTA") Report.[16] While renewable energy has no emissions, it can only generate electricity when the sun is shining, or the wind is blowing; this reliance on weather conditions can create volatility in the availability of resources to serve load from one hour to the next (and even on a sub-hourly basis). As the quantity of renewable generation grows, the magnitude of weather-related supply uncertainty is expected to increase.

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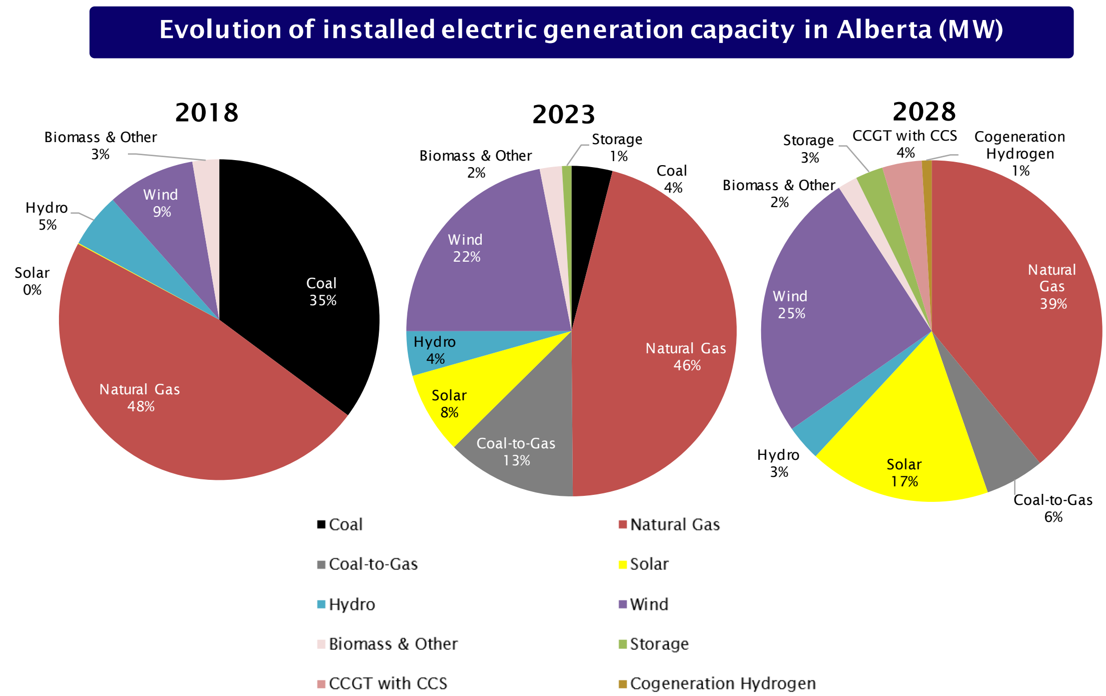
[13] Government of Canada. *Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations.* August 19, 2023.

[14] Beginning January 1, 2035, new unabated fossil-fueled units will be limited in their operation to only 450 hours per year (approximately 5% of the unit's operating capacity), to meet additional generation requirements during periods of peak electricity demand. Existing units commissioned before January 1, 2025 are expected to align with the performance emissions standard by whichever comes first – January 1, 2035, or "following the unit's end of prescribed life," which is defined as 20 years after its commissioning date. (Source: Ibid).

[15] AESO ETS. *Current Supply Demand Report.* Last accessed February 1, 2024.

[16] AESO. *Long-term Adequacy Report.* November 9, 2023.

**Figure 2. Evolution of installed electric generation capacity in Alberta**




Sources: AESO. *Annual Market Statistics Reports – 2010 to 2019*; AESO. *Annual Market Statistics Tableau Dashboard.*

Alberta has several unique characteristics that make managing these developments challenging. First, it is a relatively small electricity market with a peak demand of 12,384 MW[17] and installed capacity of 20,777 MW,[18] with import limits on interconnections to neighbouring regions (none of which have an organized energy-only market), and challenges in arranging exports to markets further away.

Second, it has a relatively simple wholesale market design, with generators only earning revenues from selling energy in the spot market and capacity into the much smaller ancillary services markets (ancillary services are procured by the AESO to support the reliable operation of the grid on a day-ahead basis). As more renewables come online, LEI's modeling indicates that Pool Prices will more frequently end up at the price floor of $0/MWh, which will mean other generators that have to pay for fuel will be running in those hours at a loss. An increasing frequency of $0/MWh prices will challenge the economics for existing power plants and new dispatchable generation investments, given that the energy-only market (and associated ancillary services markets) are the only source of revenues under the province's current electricity market design.

Third, Alberta's current market design has no mandated reliability targets – which means that there is no mechanism in the market (outside of the Pool Price) to compensate generators for investing in new or expanded generation assets to ensure that there is reliable electricity supply – and no process for ensuring the orderly retirement of generators.

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[17] AESO ETS. *Historical Pool Price.* Last accessed February 1, 2024.

[18] AESO ETS. *Current Supply Demand Report.* Last accessed February 1, 2024.

# 4 LEI used simulation modeling to dynamically assess market outcomes over the next 20 years

## 4.1 LEI is an independent consultant with deep expertise in wholesale electricity sector modeling

LEI is a global economic, financial, and strategic advisory firm specializing in energy, water, and infrastructure. The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation, transmission, and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI has worked extensively with policymakers as they deal with the energy transition due to the evolution of new technology, evolving consumer patterns, and new policy and reliability challenges. LEI has over 25 years of experience working in Alberta and with clients across the North American electricity sector. The firm has a balance of private sector and governmental clients, which informs and enables us to advise on the impact of regulatory initiatives on private investment, as well as predict the extent of possible regulatory responses to individual firm actions.

LEI has a suite of proprietary modeling tools developed and refined over decades for focused use in the electricity sector. Our modeling suite incorporates state-of-the-art statistical and game theoretic techniques for analyzing competitive wholesale markets, cost-of-service datasets for benchmarking and productivity trends, and practical and real-world financial models for advising clients on participation in complex markets and optimization of their use of electricity. Our tools are regularly relied upon by our clients to perform various market analyses or as inputs to financial and economic modeling.

## 4.2 Simulation modeling is used to embed economically rational investment and operational decisions over the 20-year timeframe

LEI used its proprietary simulation-based modeling suite to project future market outcomes and analyze the impact of renewable energy generation on supply adequacy and the cost of electricity over time. Simulation modeling is necessary because the Inquiry required an assessment of changes into the future – namely, the growth of renewables. We cannot simply assume that supply and demand remain the same. LEI completed the modeling over a 20-year timeframe, consistent with industry best practice.

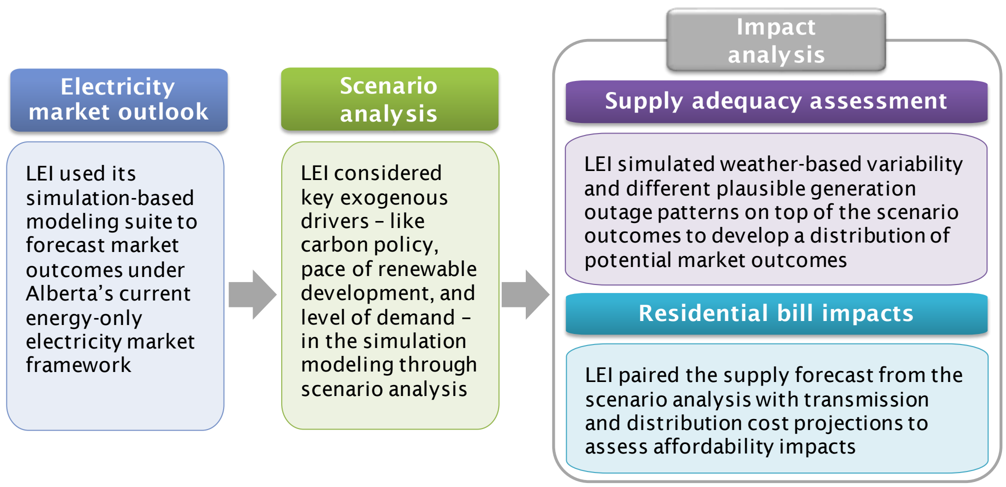
> ***What is simulation modeling?***
>
> Generally, a simulation model is intended to mimic real world dynamics. With respect to the electricity market, simulation modeling determines the dispatch of generating resources in the market (by assuming that the lowest cost generator is "dispatched" first in each hour) to meet projected hourly load, subject to technical assumptions regarding generation operating capacity and availability of transmission. This analysis will also produce a forecast of Pool Prices.

LEI's analysis entailed three separate phases:

- **Wholesale energy market modeling** to assess market price outcomes and impacts to the generation supply mix, assuming economically rational and competitive market-motivated investment decisions. LEI used a proprietary module to ensure that the critical

features of the energy-only market (i.e., economic withholding) were incorporated into the forward-looking modeled conditions.
- **Scenario analysis** to test different external market drivers, such as carbon policy pathways, pace of renewable development, and level of demand.
- **Impact analysis** to evaluate the impact of these different scenarios on supply adequacy and on residential customer electric bills.

**Figure 3. Overview of LEI's modeling approach**




More information on LEI's modeling methodology can be found in each of the Annexes.

### 4.3 LEI leveraged AESO data and analysis to develop modeling assumptions

LEI used AESO's modeling and underlying assumptions from its preliminary 2024 LTO, including AESO's load forecast, supply projections (such as new investment and retirement), and information about the cost of new generation resources.

To assess residential electric bill impacts, LEI relied on AESO's 2022 Long-term Transmission Plan[19] and more recent announcements from AESO's 2023 Grid Reliability Update Stakeholder Information Session.[20] In addition, LEI layered in other assumptions as needed, such as additional transmission costs for scenarios with higher levels of renewables, based on AESO's 2022 Net-Zero Emissions Pathways Report,[21] as well as assumptions about distribution system costs associated with integrating increasing levels of solar distributed energy resources ("DERs") and electric vehicles ("EVs"), based on the recently released 2024 Net-Zero Analysis of Alberta's Electricity Distribution System.[22]

A detailed breakdown of LEI's assumptions and sources can be found in each of the Annexes.

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[19] AESO. *AESO 2022 Long-term Transmission Plan.* January 2022.

[20] AESO. *Grid Reliability Update Stakeholder Information Session.* November 23, 2023.

[21] AESO. *AESO Net-Zero Emissions Pathways Report.* June 2022.

[22] Guidehouse (prepared for the AUC). *Net-Zero Analysis of Alberta's Electricity Distribution System.* January 22, 2024.

# 5 Key finding: supply adequacy and system reliability will deteriorate

Supply adequacy and system reliability are critical components of any electricity system. Many use the term "reliability" as a catch-all, but there is a nuanced difference. Supply adequacy focuses on having enough electricity generation supply to meet hourly demand, taking into account planned and unplanned outages and other factors that may impact demand or supply. System reliability is broader and includes elements such as inertia and frequency support.

> ***What is supply adequacy?***
>
> Supply adequacy is having enough electricity generation supply to meet hourly demand, taking into account planned and unplanned outages and other factors that may impact demand or supply.

In other words, supply adequacy is a component of system reliability. Other components of system reliability include the ability to continuously balance supply and demand and maintain adequate inertia and frequency on the grid. Therefore, supply inadequacy is one cause of poor system reliability. LEI's analysis was limited to supply adequacy.

## 5.1 Current market design and policy will result in worsening supply adequacy

LEI analyzed the Base Cases and additional scenarios to determine supply adequacy outcomes. Specifically, we estimated the average size of unserved load (in MWh or % of annual demand not met), which is the amount of demand that is not served when the system runs out of available supply to provide electricity to all customers. As a result, the AESO would have to shed some load – which means that some customers will not have electricity for some period of time. In the industry, this is sometimes also referred to as a "rolling blackout".[23]

> ***What is unserved load?***
>
> Unserved load refers to instances where not all customers' electricity demand can be met, regardless of price.

Supply adequacy worsens over time across all scenarios tested by LEI. The growing levels of intermittent renewables and decreasing amounts of dispatchable thermal generation (i.e., generation assets that can be "dispatched" at will and do not depend on weather conditions) amplify the frequency and magnitude of unserved load events. Figure 4 below shows that these supply adequacy problems start to become significant in the mid-2030s, even with "normal" weather.[24] By the late 2030s, reliability risk under the 2035 Base Case is expected to be worse than the 2050 Base Case – although under both cases, the level of reliability by the late 2030s would be at a level materially worse than what Albertans have been accustomed to, as indicated by the modeled unserved energy crossing above the AESO's Resource Adequacy Threshold (shown as the red dotted lines in the charts below). The AESO has not had to implement rolling backouts

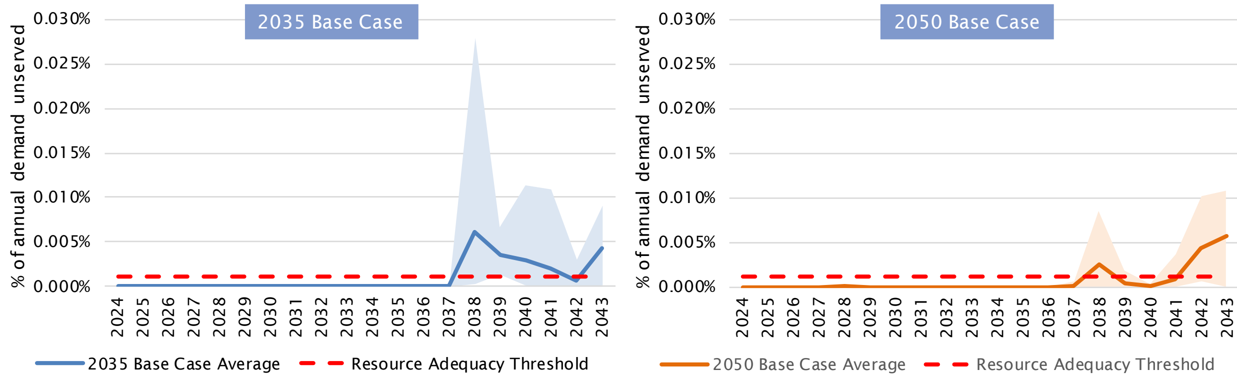
---

[23] A rolling blackout entails the system operator intentionally cutting electricity to some customers in order to balance supply and demand. A rolling blackout is therefore a partial outage of the electric system – in contrast with a system-wide blackout, where the entire system is on outage.

[24] LEI used actual weather data in its long term energy market modeling, in order to ensure realistic conditions. LEI chose to use 2021 weather conditions (which impacted hourly renewable generation and hourly variation in load) to represent "normal" weather, because 2021 conditions were closest to longer term averages and were neither mild nor abnormally extreme in terms of weather factors that could skew the scenario analysis results towards low likelihood events.

since 2013. Moreover, the level of load shed projected far exceeds anything actually observed in the modern history of the electric grid in Alberta.

**Figure 4. Comparison of levels of demand unserved under the Base Cases with normal weather**




Notes:

- LEI ran its simulation model 10 times (seeds) for each year and scenario, with varying patterns of generation outage schedules. The shaded areas in the charts above represent the range of modeled outcomes caused by these different patterns of generation outages. The solid lines represent the average across the 10 seeds.

- AESO defines the Resource Adequacy Threshold as the 1-hour average Alberta internal load for a year divided by 10. Converting to percentage terms is calculated as 1/8760/10 = 0.00114%.

***What are the Supply Adequacy Shortfall Metric and Resource Adequacy Threshold in Alberta?***

While the Alberta energy-only electricity market has no mandated reliability targets, the AESO is still required to report on long-term (2 year) resource adequacy metrics on a quarterly basis. If the AESO identifies a two-year probability of supply adequacy shortfall, the AESO may take specific preventative actions, including procuring load shed services, back-up generation, or emergency portable generation.

The AESO also develops a Long Term Outlook every two years to forecast electricity demand and generation over a 20-year horizon to inform its long-term plans. The LTO monitors resource adequacy through a Resource Adequacy Threshold. This analysis is conducted for information and planning purposes only – there is no mechanism for the AESO to procure new generation even if reliability risk is found to exceed the threshold.

LEI has presented its analysis using the same metrics and AESO's current benchmark for acceptable reliability in Alberta.

LEI used a probabilistic analysis to also assess how weather would further interact with varying generation outages. Further analysis of unserved load events indicates that, in the 5% most severe reliability events, an average of 10% of demand would not be met; similarly, the 5% worst long-duration unserved load events would last for almost an entire day on average.[25] The system is projected to have the highest reliability risk during evening hours in the winter months. This would be an unprecedented amount of load shed that Albertans have not experienced before.

This deterioration in supply adequacy is driven by the supply mix assumed in the AESO's preliminary 2024 LTO, which indicates that Alberta's energy-only market will not provide a sufficiently robust signal for additional investment in new dispatchable generation capacity.[26]

Historically, Alberta's energy-only market design, which allows generators to offer bids above their theoretical short-run marginal costs,[27] created a robust enough signal for investment needs. This negated the need for supply adequacy requirements or reserve margin mandates in Alberta to ensure that the grid had enough electric generation capacity to meet hourly demand.

However, Alberta's market design is coming under pressure from the impact of two different developments: proposed environmental policies calling for a 'net zero' mandate for electricity – which will require fossil-fuel fired generators to retrofit or face significant operational restrictions – and corporate interest in ESG – which is dramatically increasing the development of renewable generation, independent of market price signals. Renewable generation provides clean energy, but the production of that clean energy is not perfectly aligned with when consumers want their electricity, nor can renewable generators control when (and in what quantities) they produce electricity, creating an ongoing need for dispatchable generation.

As a result, the electricity system, absent market design changes, will become less reliable than it has been historically. LEI's analysis shows that the current compensation in Alberta's energy-only market – the Pool Price for energy – may not be sufficient to remunerate dispatchable generators for their fixed costs and to prevent premature retirements or sustain a level of needed incremental investment.

LEI identified that the provincial plan for decarbonization (modeled as the 2050 Base Case) produces better supply adequacy outcomes than the federal draft CER (2035 Base Case) in most years. This is primarily because the provincial plan does not limit the number of hours that unabated gas generation units can run in a year, whereas the federal draft CER limits these units to a maximum of 450 hours of operation per year. The provincial plan thus allows natural gas

---

[25] As a point of reference, Storm Uri in 2021 resulted in an estimated load shed of up to 26% of demand in Texas, lasting for approximately 72 hours.

[26] LEI's simulation model tracks the revenues earned and costs incurred by generation assets in the energy market. LEI compared the forecast of net profits (after taking into account fixed operating and maintenance ("O&M") costs) of the generation assets against the capital costs. The results confirm AESO's findings that additional investment cannot be supported by the forecast market prices. In addition, LEI's modeling shows that under the forecast conditions, dispatchable new generation is generally not earning a robust return on investment expected for merchant generators until the late 2030s. See Annex 1 *(Scenario Analysis: Long Term Weather-Normal Energy Market Forecast)* for more details.

[27] Short-run marginal costs ("SRMCs") consist of costs associated with an incremental unit of energy supplied. The largest component of the SRMC for fossil fuel-fired power plants is typically fuel costs (e.g., coal or natural gas prices multiplied by the thermal efficiency of the generating unit in question). The SRMC also contains other non-fuel variable O&M expenses, such as consumables used by the facility's operations to generate the energy, as well as costs associated with carbon emissions.

generators to provide better support to the grid when intermittent renewable generation output is low, or when there are outages of many generation units.

One important caveat is that LEI's analysis does not consider technology risks associated with the new generation technologies assumed in AESO's preliminary 2024 LTO, including hydrogen-based generation, natural gas-fired generators retrofitted with carbon capture technologies, and small modular nuclear reactors. AESO's preliminary 2024 LTO analysis assumes significant investments in these technologies, which have not yet been proven on a commercial scale in Alberta or in any other jurisdiction. LEI has not investigated the feasibility of the construction schedules assumed in AESO's supply forecast. LEI has also employed AESO's capital cost assumptions in completing its financial analysis on the economics of investment. Furthermore, LEI assumed that these new technologies will have the same level of reliable operation as existing natural gas-fired or nuclear units. However, if these new technologies are in fact less reliable than LEI assumed, more costly, or likely to be materially delayed beyond their projected in-service dates, then the level of supply adequacy risk would be worse than projected in LEI's modeling.

## 5.2 Additional renewables exacerbate supply adequacy problems by squeezing out dispatchable generation

These supply adequacy problems are exacerbated if more renewable generation is built than what is assumed in the Base Cases. More renewable energy capacity creates a higher frequency of $0/MWh Pool Price incidents, as shown in Figure 5 below. This reduces the profitability of thermal generators, with existing thermal generators more likely to retire and potential new thermal generators less likely to enter the market. Fewer dispatchable generators creates more supply adequacy concerns. For example, in the 2050 More Renewables Calibrated Case, 125 MW of gas-fired units that would have entered the market under the 2050 Base Case are no longer economically viable, as their pre-tax returns would be in the low single digits, too low for investors to consider. Moreover, this increases the province's vulnerability to weather, where lower levels of wind or solar irradiation will have a bigger impact on the electricity system.

**Figure 5. Number of hours with Pool Prices at zero under normal weather conditions**

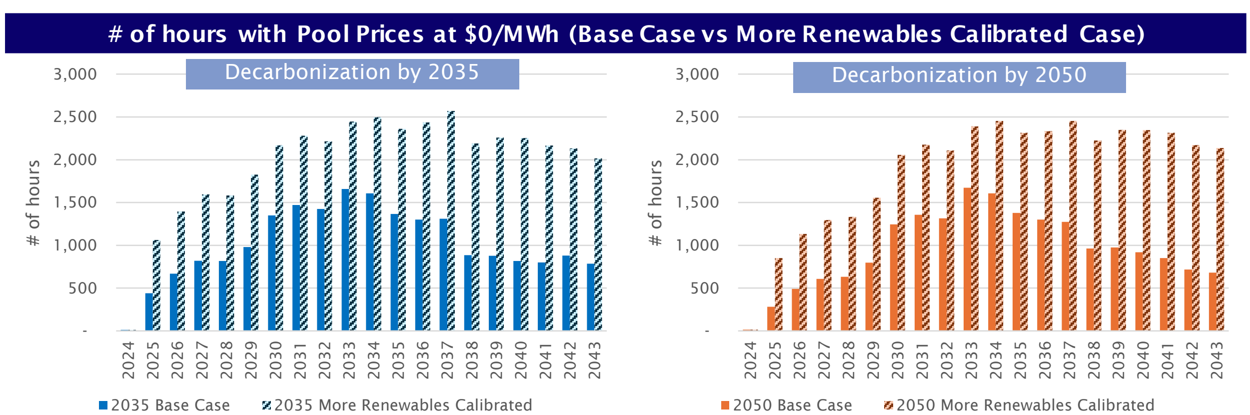
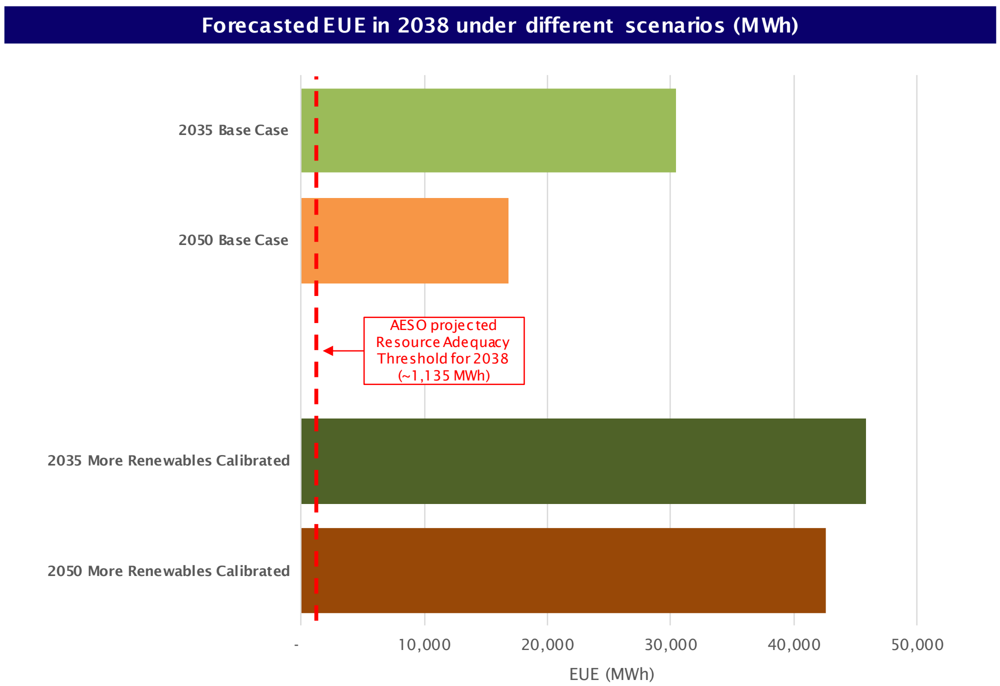



Figure 6 below compares the forecasted expected unserved energy ("EUE") under the various scenarios for the year 2038 (after all coal-to-gas units are expected to retire) relative to the AESO's Resource Adequacy Threshold for the same year (see red dotted line). With higher renewables, the modeled EUE exceeds 40,000 MWh, as compared to ~10,000 MWh under the 2050 Base Case and ~30,000 MWh under the 2035 Base Case, in all cases significantly higher than the AESO's Resource Adequacy Threshold of ~1,135 MWh. As compared to the Base Cases, the cases with higher renewables are expected to have more frequent, longer duration unserved load events, with more MWs of unserved load on average (i.e., more consumers being affected).

**Figure 6. Expected unserved energy under Base Cases vs More Renewables Calibrated Cases for 2038**




## 5.3 Retirements of older coal-to-gas units in the near term may exacerbate grid reliability under abnormal weather conditions

LEI observes that there are higher amounts of unserved energy under both Base Cases once coal-to-gas units start to retire, which may be as early as 2025, under certain abnormal weather conditions.

Two near-term coal-to-gas retirement schedules were considered, consistent with the AESO's supply projections. First, under the 2035 Base Case, 2.2 GW of coal-to-gas units were assumed to retire before 2025; second, under the 2050 Base Case, a higher level of coal-to-gas unit retirements was assumed – 2.6 GW before 2025. In both cases, 2.9 GW of new dispatchable resources were added from 2023-2025, consistent with the AESO's supply projections. Under the 2050 Base Case (the scenario with more coal-to-gas retirements), LEI's analysis projects EUE that breaches the AESO's thresholds as early as 2025, indicating a higher risk of load shed under abnormal weather. Specifically, modeled EUE reaches 2,450 MWh in 2025, which exceeds both AESO's Long-Term Resource Adequacy Threshold of 1,135 MWh, and AESO's Two-Year Probability of Supply Adequacy Shortfall Metric of 2,005 MWh from the November 2023 LTA Report. Once additional investment comes online, the projected EUE declines below the thresholds.

This observation implies that significant retirements may – at least temporarily – result in deteriorating supply adequacy to levels that may not be acceptable.

# 6 Key finding: average Pool Prices are expected to increase

## 6.1 Average Pool Price increases are driven by decarbonization policies

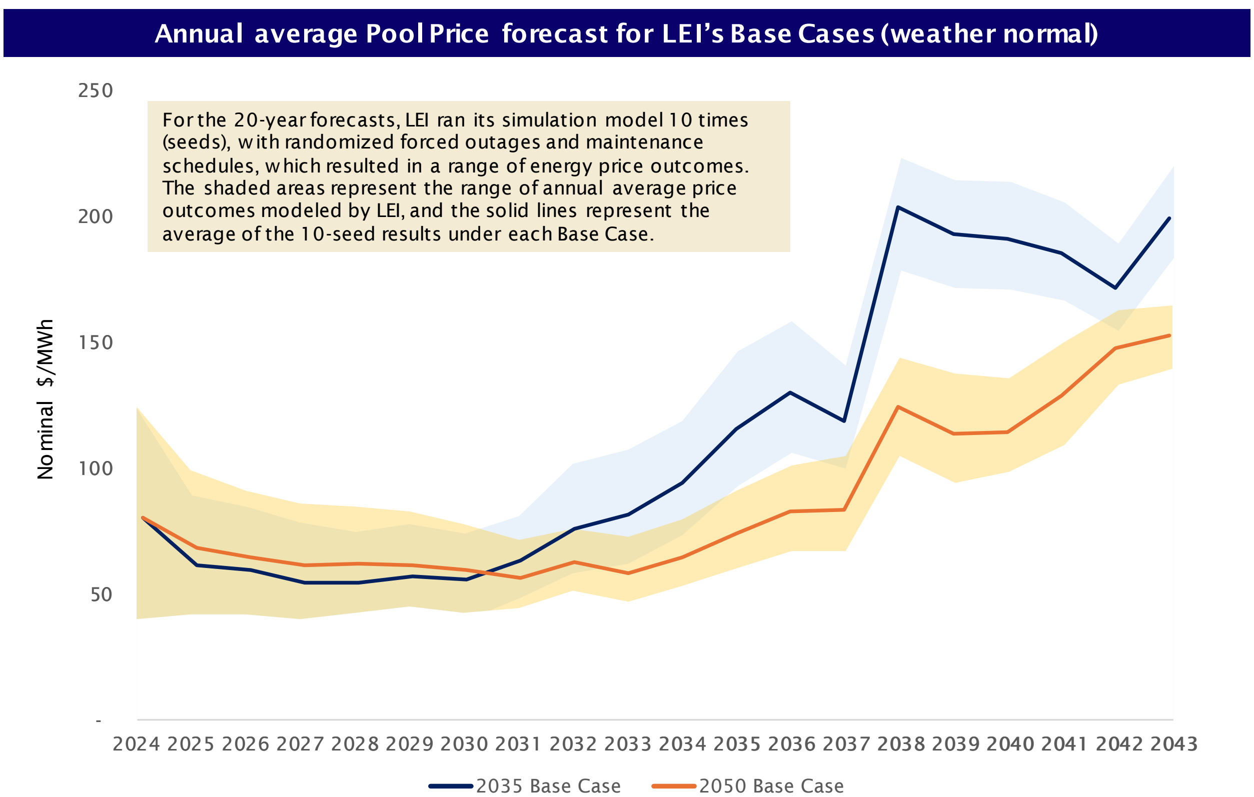
Average Pool Prices increase over the modeling time horizon, primarily due to two factors. First, carbon costs guided by decarbonization policies increase Pool Prices. Thus, due to the more stringent carbon emissions limitations of the federal draft CER, Pool Prices are higher under the 2035 Base Case than the 2050 Base Case.

Second, Pool Prices become more volatile over time, with more frequent price spikes and zero prices due to renewables coupled with a tightening capacity reserve margin. The price spikes, in some hours, are the result of load shed due to supply inadequacy, as discussed in Section 5.

> ***How do the federal draft CER and provincial plan differ?***
>
> There are two primary differences. First, the federal draft CER pursues decarbonization by 2035, whereas the provincial plan pursues decarbonization by 2050. Second, the federal draft CER sets more stringent carbon emissions limitations – unabated gas generation units can only run up to a maximum of 450 hours per year; the provincial plan does not have a similar limitation.

This long-term increase in Pool Prices exceeds inflation after 2030, but is still not sufficient to support the level of electric system reliability that Albertans have been used to (as discussed in Section 5).

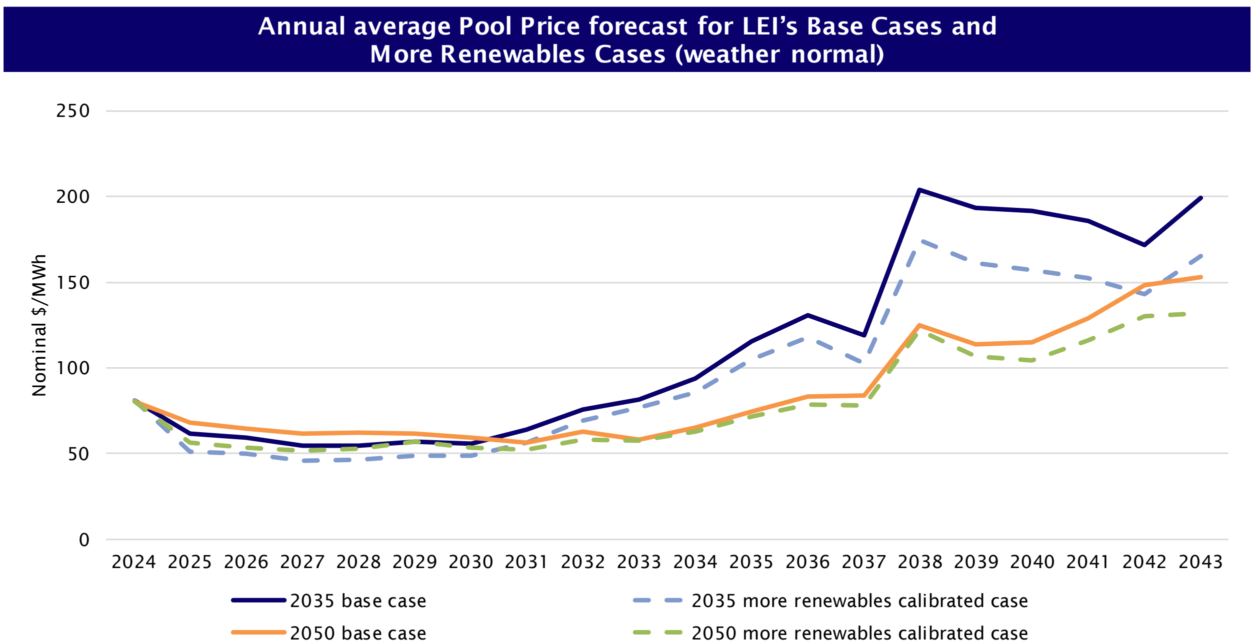
**Figure 7. Comparison of Pool Price forecast under 2035 and 2050 Base Cases**



## 6.2 Additional renewable capacity will decrease Pool Prices

Intermittent renewables such as wind and solar offer their energy at $0/MWh in the energy market. Therefore, additional renewable capacity will put downward pressure on forecast Pool Prices. In turn, this reduces the profitability of thermal generators, with existing thermal generators more likely to retire and potential new thermal generators less likely to enter the market. Thus, the system becomes more prone to price spikes (due to increasing weather scarcity events and unserved energy events) and more frequent zero prices. The impact on Pool Prices due to additional renewable capacity is illustrated in Figure 8 below. While the annual average Pool Prices are lower with additional renewable capacity, the system is also less reliable (as discussed in Section 5.2).

**Figure 8. Pool Prices assuming more renewable capacity**

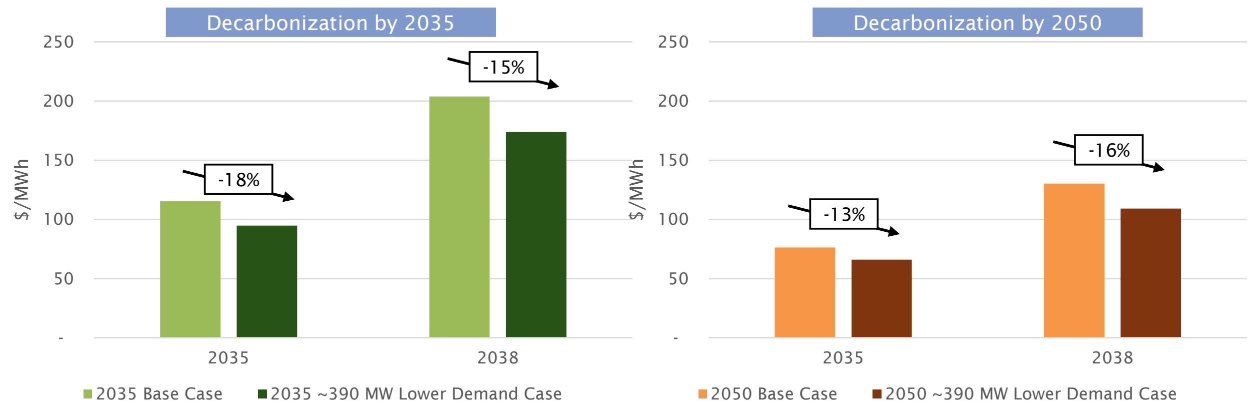



## 6.3 Relatively small changes in demand have a large impact on Pool Prices

Fairly small changes in demand have a profound impact on Pool Prices because we are assuming very tight supply-demand conditions in the longer term, much tighter than what we have experienced in the last 20 years in Alberta. Lower demand reduces average Pool Prices by a greater amount than the percentage change in demand, as illustrated in Figure 9 below.[28] Under the 2035 Base Case, when demand is decreased by 3.5%, annual average Pool Prices decrease by 15% to 18%. Similarly, under the 2050 Base Case, 3.5% lower demand decreases annual average Pool Prices by 13% to 16%.

[28] LEI ran the Lower Demand Cases for 2035 and 2038 only.

**Figure 9. Change in annual average Pool Prices due to ~390 MW (-3.5%) lower demand in 2035 and 2038**




At the same time, lower demand leads to improvements in supply adequacy, as there are fewer hours where there is insufficient supply to meet this lower demand. The decrease in the number of hours with unserved load (with $1,000/MWh hourly Pool Prices) contributes to the reduction in annual average Pool Prices.

The modeling results from the scenarios with lower demand highlight the importance of potential flexible demand-side resources in an energy-only market. By holding the supply mix constant and observing how lower demand results in improved supply adequacy, we estimate that between 850 to 1,200 MW of additional dispatchable demand-side resources by 2038 could reduce unserved energy events to levels within the AESO's forecasted Resource Adequacy Threshold.[29]

[29] Assuming these additional dispatchable demand-side resources are available at all times and can be dispatched when needed.

# 7 Key finding: residential electric bills increase in line with Pool Prices

## 7.1 Residential electric bills outpace inflation in the later years of the forecast period – while reliability is reduced

> ***How to assess affordability?***
>
> Affordability is not an economic term, it is a subjective term. Thus, LEI used inflation as a yardstick to compare the projected electric bill impacts against.

LEI compared the projected increase in residential electric bills to inflation as a proxy for assessing "affordability." Under all scenarios, residential electric bills are expected to rise above the rate of inflation in the later years of the modeled time horizon, closely tracking the trajectory of Pool Prices under the various scenarios. Residential electric bills increase the most under the 2035 Base Case, with a province-wide average compound annual growth rate ("CAGR") of 1.9% per year from 2025 to 2030 and then a much higher CAGR of 6.8% per year from 2030 to 2040. Under the 2050 Base Case, increases are more moderate: residential electric bills province-wide rise by a CAGR of 1.6% per year from 2025 to 2030 and 4.3% per year from 2030 to 2040. In contrast, LEI's inflation assumption for 2024 to 2040 averages 2.0% per year, consistent with AESO's long-term inflation assumption.[30]

The biggest driver of rising electric bills is the energy supply component, not the cost of transmission and distribution. However, there is some uncertainty about the amount of future transmission and distribution investments needed to accommodate increased renewables, solar DERs, and EVs. In addition, in rural service territories like ATCO, the wires portion of a typical residential electric bill is already relatively high.

Importantly, these higher electric bills correspond to a lower level of electric system reliability than Albertans have been accustomed to (as discussed in Section 5).

Details on this and other observations are available in Annex 2 *(Projection of Residential Electric Bills)*.

## 7.2 More renewable capacity will lower residential electric bills but make service even less reliable

With additional renewables, residential electric bills are projected to be lower than in the Base Cases, although the impact of lower Pool Prices is somewhat offset by the larger transmission investments needed to enable that renewables development. Under these higher renewables cases, residential electric bills under the 2035 More Renewables Calibrated Case are projected to increase at a CAGR of 2.6% per year from 2025 to 2030 and 6.2% per year from 2030 to 2040; residential electric bills under the 2050 More Renewables Calibrated Case are projected to increase at a CAGR of 2.4% per year from 2025 to 2030 and 4.2% per year from 2030 to 2040. This is

[30] For 2024-2026, LEI's inflation assumption is based on the average Alberta Consumer Price Index ("CPI") forecasts from the big five banks and the Government of Alberta; for 2027 onwards, LEI assumed 2% inflation, consistent with the AESO's long-term inflation assumption. See Annex 2 *(Projection of Residential Electric Bills)* for more details.

illustrated in Figure 10 below. However, as discussed in Section 5, more renewable capacity makes Alberta's electric grid even less reliable.

**Figure 10. Comparison of change in projected monthly residential electric bills under various scenarios**

**Projected residential electric bill CAGRs by DFO and scenario**

*2035 Base Case*
*(Federal draft CER)*

| DFO | 2025-2030 CAGR | 2030-2040 CAGR |
|---|---|---|
| ATCO | 2.1% | 5.5% |
| EPCOR | 1.9% | 7.4% |
| ENMAX | 1.6% | 7.7% |
| Fortis | 1.9% | 6.7% |
| Province avg. | 1.9% | 6.8% |

*2035 More Renewables Calibrated Case*
*(Federal draft CER with more renewables)*

| DFO | 2025-2030 CAGR | 2030-2040 CAGR |
|---|---|---|
| ATCO | 2.6% | 5.0% |
| EPCOR | 2.7% | 6.7% |
| ENMAX | 2.5% | 7.0% |
| Fortis | 2.7% | 6.1% |
| Province avg. | 2.6% | 6.2% |

*2050 Base Case*
*(Provincial plan)*

| DFO | 2025-2030 CAGR | 2030-2040 CAGR |
|---|---|---|
| ATCO | 1.9% | 3.7% |
| EPCOR | 1.6% | 4.6% |
| ENMAX | 1.3% | 4.7% |
| Fortis | 1.7% | 4.1% |
| Province avg. | 1.6% | 4.3% |

*2050 More Renewables Calibrated Case*
*(Provincial plan with more renewables)*

| DFO | 2025-2030 CAGR | 2030-2040 CAGR |
|---|---|---|
| ATCO | 2.4% | 3.6% |
| EPCOR | 2.4% | 4.5% |
| ENMAX | 2.2% | 4.5% |
| Fortis | 2.4% | 4.1% |
| Province avg. | 2.4% | 4.2% |

Note: LEI presents CAGRs for 2025-2030 and 2030-2040, as 2030 is the year where Pool Prices begin to diverge between the various scenarios (as shown in Figure 8 in Section 6.2).

# 8 Roadmap to more detailed information

LEI provides three Annexes with more detailed information on the inputs employed and modeling results. Each Annex provides detail on the modeling approach, the different scenarios analyzed, key underlying assumptions and inputs, and modeling results and findings.

The three Annexes are:

- **Annex 1 – Scenario Analysis: Long Term Weather-Normal Energy Market Forecast** presents the 20-year modeling exercise conducted by LEI for the various scenarios (Base Cases, More Renewables Cases, and Lower Demand Cases) assuming normal weather;
- **Annex 2 – Projection of Residential Electric Bills** presents LEI's approach to estimating electric bills by distribution facility owner ("DFO") for a typical residential customer under the various scenarios; and
- **Annex 3 – Probabilistic Supply Adequacy Analysis** presents the probabilistic analysis conducted by LEI that introduces weather-based variability to test the impact on supply adequacy.

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# Module B Study – Annex 1
# Scenario Analysis: Long Term Weather-Normal Energy Market Forecast

*prepared for*

Proceeding 28542: AUC Inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta

February 7, 2024

www.londoneconomics.com

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# Agenda

| | |
|---|---|
| 1 | **Modeling approach** |
| 2 | Key assumptions and inputs |
| 3 | Key modeling results |

# LEI conducted forward-looking simulations of the Alberta power market using a scenario-based approach, in order to estimate future supply adequacy and a typical residential customer's electric bill

### Wholesale electricity market outlook

LEI used its simulation-based modeling suite to forecast market outcomes under **Alberta's current energy-only market framework** – leveraging information from AESO's preliminary 2024 Long-term Outlook ("LTO")

### Scenario analysis

LEI considered key exogenous drivers – like carbon policy, pace of renewable development, and level of demand – in the simulation modeling through scenario analysis and sensitivities

*Focus of this Annex*

### Impact analysis

#### Probabilistic assessment of reliability

To assess supply adequacy*, LEI simulated weather-based variability and different plausible generation outage patterns on top of the scenario outcomes to develop a distribution of potential market outcomes

#### Total electric bill impacts

LEI paired the supply forecast emerging from the scenario analysis with transmission and distribution cost projections to assess affordability impacts for residential customers

** LEI's terms of reference focus on supply adequacy, notwithstanding other dimensions of system reliability.*

# LEI's proprietary tools provide the necessary functionality for an accurate representation of Alberta's electricity market

**Simulation-based dispatch model that projects a single market-clearing price for each hour**

## POOLMod

- LEI's proprietary simulation dispatch model
- Consists of several key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch

**Above SRMC offer behaviour provides an investment signal under the energy-only market**

## ConjectureMod

- Game theory module within POOLMod for the Alberta market
- Projects above short-run marginal cost ("SRMC") offers, replicating real-world outcomes; offers will be dynamic and change daily with evolving market conditions

**Probabilistic assessment of weather-related factors**

## WeatherMod

- Assesses reliability and resource adequacy and tests the resiliency of the system to plant outages and varying weather conditions
- Allows for stochastic variation of generation outages, and consideration of weather patterns and their impact on load, intermittent renewable generation, as well as unplanned outages

*Focus of this Annex*

# Key facets of the simulation-based modeling were selected to comply with the overarching study goals in the timeframe allotted, while maintaining the necessary analytical rigor

Reflect the current energy-only market design and associated policies

Leverage existing relevant studies and analysis

Simulation of future supply mix

Completion by the deadline imposed by Government

Consideration of a range of scenarios

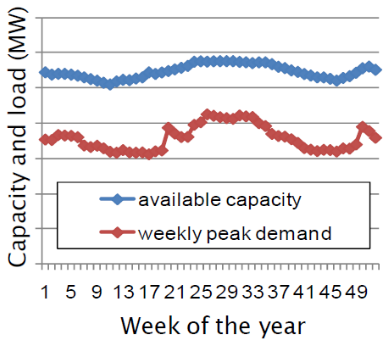
**LEI's modeling and analysis assumed the following:**

- market design consists of a **single clearing price real-time energy-only market** with simple price/quantity offers
- **offers above marginal costs** continue to be permitted, in order to provide an investment signal under the current market design
- real-time energy price is limited to a **$0/MWh floor and $1,000/MWh cap**
- **no day-ahead unit commitment**; **no start-up cost recovery guarantees**
- the **existing Transmission Regulation policy is maintained**, such that LEI's modeling assumes an uncongested transmission system and continues to use a single clearing price for all generation producing energy in a given hour

# POOLMod, LEI's proprietary electricity market simulation model, forecasts availability of resources, then simulates dispatch of resources to meet projected demand and set hourly Pool Prices

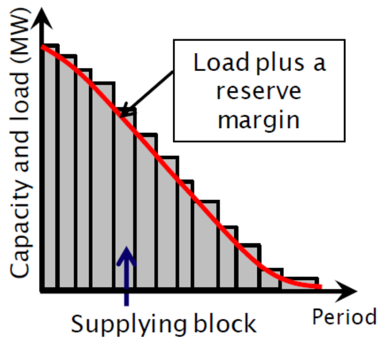
## POOLMod employs a three-stage simulation process:

### 1 Weekly
### Maintenance schedule



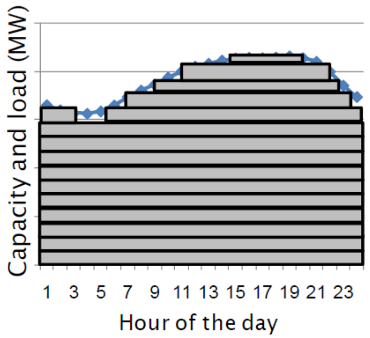

- A hypothetical, plant-specific maintenance schedule is determined on a weekly basis
- In general, more plants are scheduled on maintenance during months with lower demand

### 2 Daily
### Commitment




- Hours in the day are sorted from highest to lowest load and available resources are ranked/matched
- On a daily basis, the ConjectureMod algorithm develops economically rational above SRMC offers for assets controlled by key market participants
- POOLMod creates an energy merit order based on offers from available resources

### 3 Hourly
### Dispatch




- Dispatch occurs on a chronological hour-by-hour basis based on energy merit order, taking into account forced outages, intermittent generation, technical features of thermal plants (min. stable, etc.), intra-day constraints, inter-day information on stored energy and scheduled maintenance, and the offer strategy developed using ConjectureMod

# ConjectureMod, LEI's game theory module, models market participant bidding behaviour dynamically with evolving market conditions

## Process diagram

1. Modeler defines "strategy space" and marginal cost baseline

**ConjectureMod**

2. Test offers <u>above</u> marginal costs for each day for a generation owner, in search of a higher profit

**POOLMod**

3. Simulate dispatch and market clearing price based on identified offers above SRMC

*Multiple iterations to identify local equilibrium*

**On a daily basis, ConjectureMod estimates economically rational bids above marginal costs for each generation owner that reflects the availability of its resources, daily peak demand conditions, and total supply offers from competitors**

# POOLMod (including ConjectureMod) is run 10 times for each scenario to assess the range of potential outcomes with varying maintenance schedules, forced outages, and bidding behaviour

- **While WeatherMod is not used for the results covered in this Annex, there are still variables in POOLMod and ConjectureMod that impact simulated results, even under identical supply mix, demand, and fuel price settings**
- **These variables are randomized in each POOLMod "seed" run**

| Maintenance schedule | Forced outages | Offer behaviour |
|---|---|---|
| • Each unit has a required # of weeks per year for maintenance<br>• There are many combinations of maintenance schedules that can satisfy the requirements of the units<br>• In each "seed", POOLMod chooses a different maintenance schedule | • Each unit has its own forced outage rate<br>• The forced outage rate determines the probability that a unit is on outage in each day<br>• POOLMod uses a randomizer to determine whether a unit is on outage on a daily basis | • The strategy space for economic withholding for each market participant is very large – multiple solutions (equilibria)<br>• ConjectureMod uses an iterative process to test different offer strategies until it identifies a convergence point |

- **In this Annex, we show the modeling result averaged across the 10 seeds**

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# Scenarios examine different decarbonization policy pathways, varying levels and pace of renewables development, and lower levels of demand

| Two "Base Case" scenarios based on AESO's preliminary 2024 LTO; these scenarios represent two different decarbonization policy pathways to net zero | |
|---|---|
| *2035 Base Case* | *2050 Base Case* |

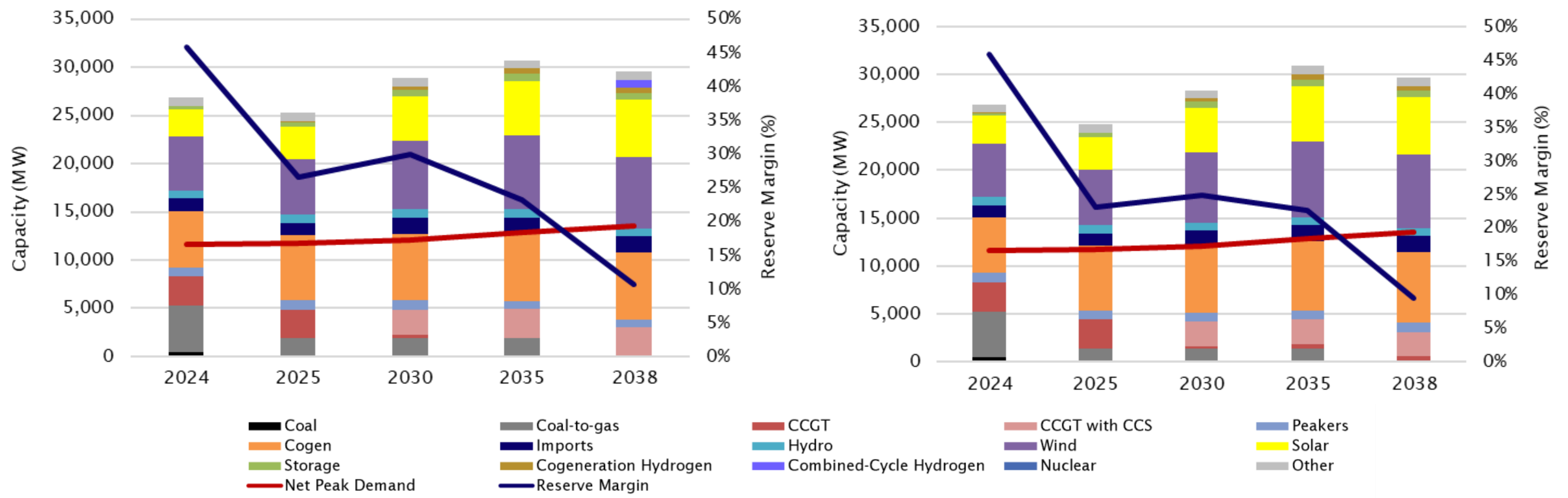
| A set of additional scenarios to consider the implications of increasing renewables on the feasibility of new entry and economics of existing resources and retirements | |
|---|---|
| *1. 2035 Additional Renewable Entry in Long Term* | *1. 2050 Additional Renewable Entry in Long Term* |
| *2. 2035 Accelerated Renewable Entry in Short Term* | *2. 2050 Accelerated Renewable Entry in Short Term* |
| *3. 2035 More Renewables Case (combo of 1 and 2)* | *3. 2050 More Renewables Case (combo of 1 and 2)* |
| *4. 2035 More Renewables Case Calibrated* | *4. 2050 More Renewables Case Calibrated* |

The More Renewables Cases introduce 4,520 MW of additional renewables (relative to the Base Cases) over the forecast period

| LEI also tested "demand shocks"* that reduce load by 3.5% and 7.2% (or about 390 MW and 800 MW in each hour), respectively, for select years (2035 and 2038) | |
|---|---|
| *2035 ~390 MW Lower Demand Case* | *2050 ~390 MW Lower Demand Case* |
| *2035 ~800 MW Lower Demand Case* | *2050 ~800 MW Lower Demand Case* |

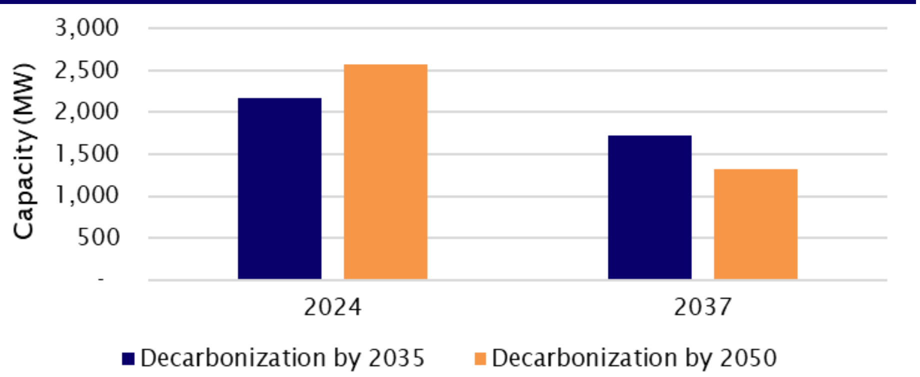
* Demand shocks are unexpected changes in demand, the underlying causes of which could reflect a variety of circumstances at a global and/or local level.

# LEI's Base Cases leverage AESO's preliminary 2024 LTO modeling work, including AESO's load forecast and supply assumptions (retirements, entry)




Note: Reserve margin is defined as dispatchable resources availability adjusted capacity divided by net peak demand. "Other" refers to biomass and demand response.

## Coal-to-gas retirement schedules




- **Retirement schedules for coal-to-gas units differ between the AESO's 2035 and 2050 scenarios**
  - This leads to different MWs of dispatchable capacity vs renewable capacity
  - The 2050 Base Case has less dispatchable MWs than the 2035 Base Case, and as such has a tighter reserve margin between 2025 and 2038
  - The average reserve margin between 2025 and 2035 under the 2050 Base Case is 23%, compared to 27% under the 2035 Base Case

# LEI tested several variations to develop the More Renewables Cases: additional renewables of about 2,100 MW in the near term, as well as additional renewables of 2,400 MW in the longer term

## Renewables cases tested:

### Additional Renewable Entry in Long Term (Back-End)

- Addition of 200 MW of wind and 200 MW of solar in each year after the final new addition in the 2035 Base Case and 2050 Base Case
- 200 MW is consistent with AESO generic additions in previous years

### Accelerated Renewable Entry in Short Term (Front-End)

- Accelerated wind and solar additions in the near term
- Additions determined by the shortfall of capacity (in MW) between AESO's November 2023 Long-term Adequacy ("LTA") Report and preliminary 2024 LTO

### More Renewables Cases under the two different carbon policy pathways

- Incorporates the back-end and front-end additions to both the 2035 and 2050 Base Cases, resulting in a 2035 More Renewables Case and a 2050 More Renewables Case

The More Renewables Cases allow LEI to test the impact of more renewables on the grid in terms of supply mix, system reliability (supply adequacy), and affordability

### Yearly Additions (MW)

| Wind | 2025 | ... | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|
| Back-End Additions | - | ... | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| Front-End Additions | 350 | ... | - | - | - | - | - | - | - |
| **More Renewables Case** | **350** | **...** | **200** | **200** | **200** | **200** | **200** | **200** | **200** |

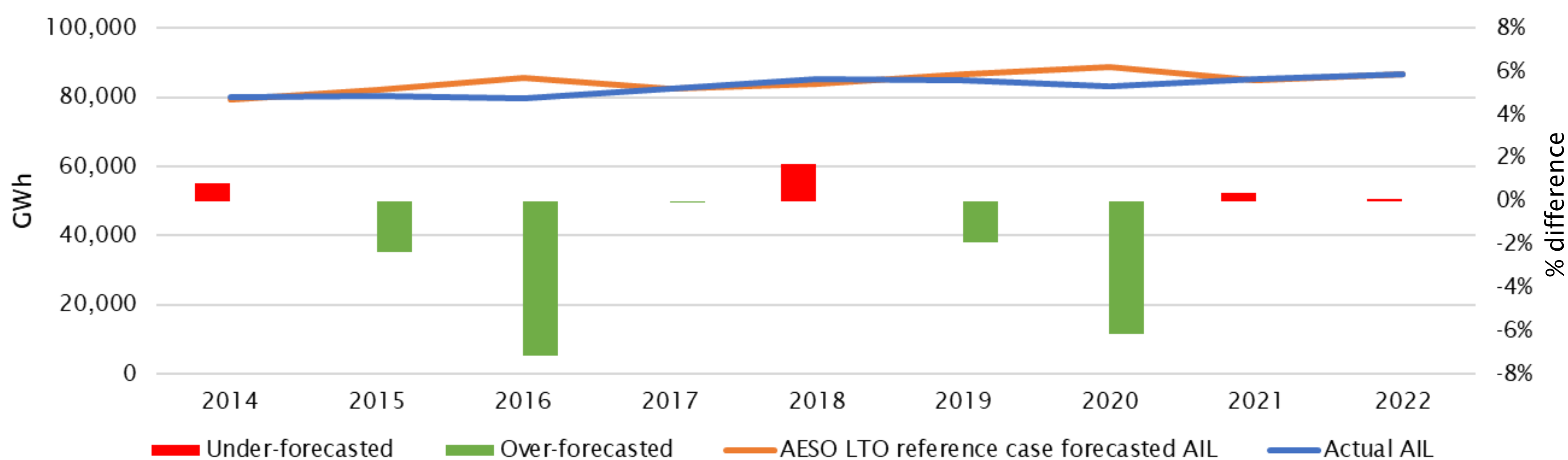
| Solar | 2025 | ... | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|
| Back-End Additions | - | ... | - | - | 200 | 200 | 200 | 200 | 200 |
| Front-End Additions | 1,770 | ... | - | - | - | - | - | - | - |
| **More Renewables Case** | **1,770** | **...** | **-** | **-** | **200** | **200** | **200** | **200** | **200** |

Note: Omitted years indicate no generic additions. Front-end additions reflect additional capacity incremental to the AESO's generic additions.

# LEI's Low Demand Cases have been developed based on the observed differences between forecasted and actual AIL demand

- **The purpose of the Lower Demand Cases is to understand the impact of a demand shock on Pool Prices and reliability**
  - Demand shocks are demand changes that are unanticipated; therefore, the system is not developed in anticipation of this level of demand
- **Over the 2014-2022 timeframe, AESO's LTO forecasts have been greater than actual realized demand in four instances (green bars in the chart below)**
  - The average difference between forecasted and actual AIL demand was 3.5% (green bars in the chart below), while the maximum difference was 7.2% (for 2016, with the forecast completed in the 2014 LTO)
- **LEI developed the Lower Demand Cases by reducing the Base Case demand by 3.5% and 7.2% (or ~390 MW and ~800 MW per hour), reflecting the average and largest historical differences between forecasted and actual AIL demand**

**Historical AESO LTO forecasted AIL demand vs actual AIL demand (GWh) and % difference**




Sources: AESO 2014, 2017, 2019, and 2021 LTO.

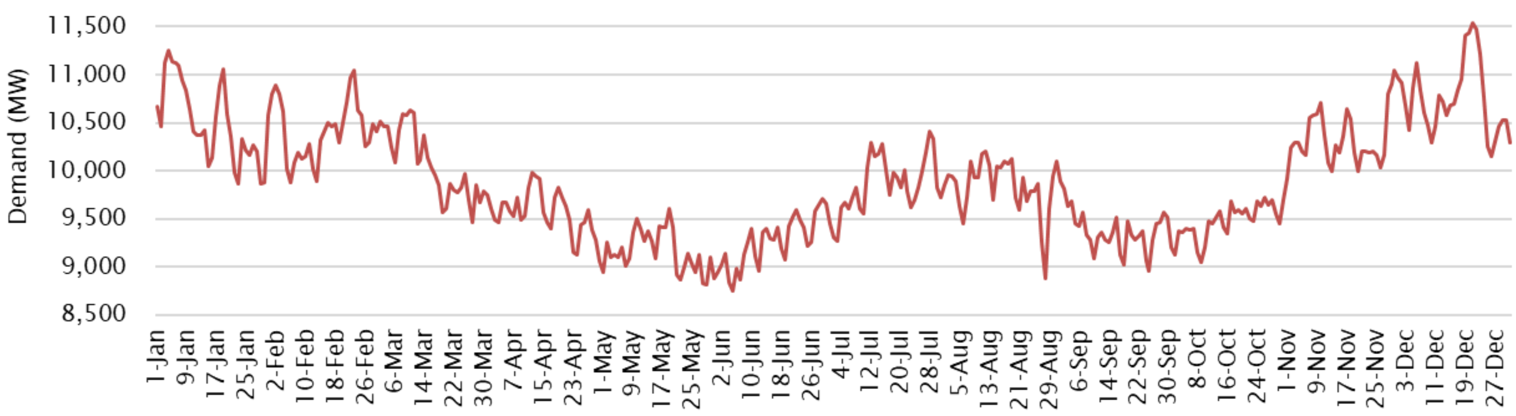
# Agenda

| | |
|---|---|
| 1 | Modeling approach |
| **2** | **Key assumptions and inputs** |
| 3 | Key modeling results |

# Demand-related inputs are taken primarily from AESO preliminary 2024 LTO data, as well as historical actuals

- **Demand in Alberta follows a diurnal trend and is largely driven by seasonal patterns, typically reaching its highest peak in the winter**
- **Peak demand and total energy consumption are based on AESO's AIL forecast from its preliminary 2024 LTO analysis, applied to a weather normal hourly profile (based on 2021 actuals), adjusted for behind-the-fence load with on-site generation**
  - LEI also used AESO load modifiers for DER, hydrogen, heating, projects, and energy efficiency
  - Incorporating Market Surveillance Administrator ("MSA") data from 2018-2022, where 9.5% of load is served by non-energy merit order resources, LEI estimated that on average 923 MW of AIL load is served by non-energy merit order resources
- **LEI used actual weather data in its assessment, in order to ensure realistic conditions**
  - LEI chose to use 2021 weather conditions (which impacted hourly renewable generation and hourly variation in load) to represent "normal" weather, because 2021 conditions were closest to longer term averages and were neither mild nor abnormally extreme in terms of weather factors that could skew the results towards low likelihood events
- **Hourly demand projections are the same across the 2035 and 2050 Base Cases and the More Renewables Cases for the weather normal model runs**

**Historical daily average demand profile, 2021 (MW)**



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# Key assumptions and inputs used for the forward modeling exercise align with AESO's preliminary 2024 LTO projections and historical observed trends

## Solar and wind generation profiles

- **Hourly solar and wind generation profiles based on 2021 actuals**
  - After analyzing hourly wind and solar patterns between 2018 to 2022, LEI found that 2021 was the year where capacity factors of wind and solar were closest to longer term averages
  - LEI assumes zero-priced offers for wind and solar, consistent with observed market dynamics
  - New wind and solar assets are assumed to have higher capacity factors, based on expected wind/solar capacity factors for units located in Class 7 (wind) and Class 10 (solar) from the National Renewable Energy Laboratory ("NREL")'s 2022 Annual Technology Baseline ("ATB") forecast

## Hydro generation profile

- **Hydro generation is based on the average historical hourly generation pattern of hydroelectric units from 2015 to 2023**
- **Hydro capacity is separated into run-of-river and peaking hydro units based on their historical generation pattern**
  - Run-of-river hydro units offer at $0/MWh
  - Peaking hydro units have a daily energy budget, where they allocate energy to the highest-priced hours for dispatch
  - Peaking hydro units offer at a "shadow price" based on the expected offer of the marginal unit that would otherwise clear the market; this is intended to reflect the economic opportunity costs for the peaking assets that are energy-limited

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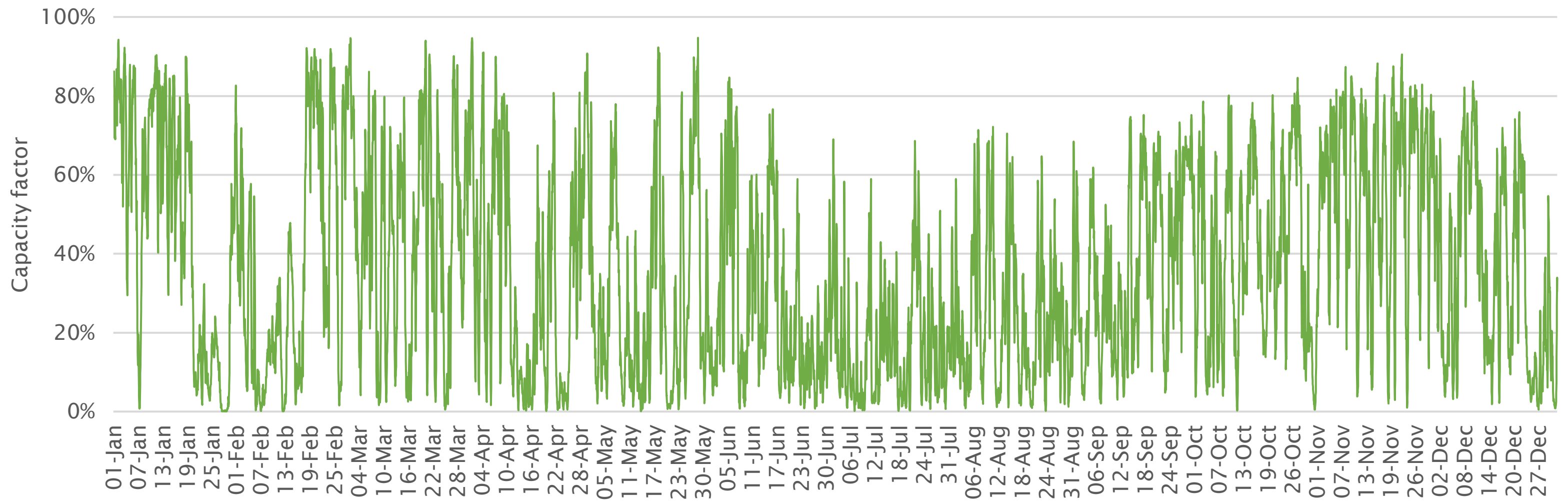
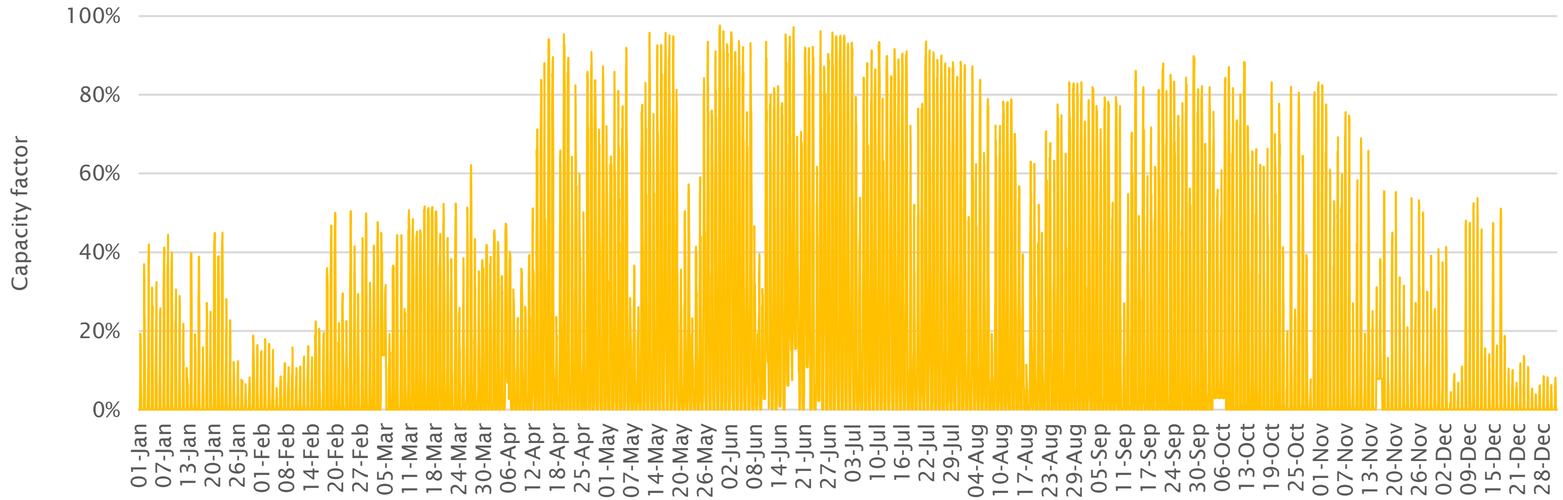
# Actual 2021 historical wind and solar capacity factors are used to reflect realistic wind and solar output patterns

## Historical hourly wind capacity factor, 2021 (%)




## Historical hourly solar capacity factor, 2021 (%)



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# Generators are not always available to be dispatched due to scheduled (maintenance) and unplanned (forced) outages – this uncertainty is reflected in LEI's simulations

- **Given Alberta's relatively small market size, the timing of outages can have a significant impact on Pool Prices – therefore LEI ran 10 iterations ("seeds") for each scenario, resulting in different outage patterns within the year (but the same overall level of outages)**
  - Economic withholding strategies also vary with each seed (although the starting strategy is the same each day, the model allows for an iterative analysis of alternative strategies as it seeks the most profitable outcomes and therefore can converge around a different solution – there are multiple possible local equilibria)
- **Outages for non-renewable generation are captured by incorporating technology-specific data on scheduled and unplanned outage levels that the North American Electric Reliability Corporation ("NERC") collects from power plant owners across all power systems under its jurisdiction in North America and summarizes in an annual publication – the Generating Availability Data System ("GADS")**
  - LEI relied on the latest NERC GADS "Generating Unit Statistical Brochure 4 - 2018-2022 - All Units Reporting" report to populate the generation schedules for non-renewable resources

**Maintenance schedule**

- Each unit has a required number of weeks of maintenance each year
- There are many combinations of maintenance schedules possible in an electric system with many plants
- For each new "seed", POOLMod resets the maintenance schedule

**Forced outages**

- Each unit has its own forced outage rate
- The forced outage rate determines the probability that a unit is on outage in each day
- POOLMod uses a random process to determine whether a unit is on outage on a daily basis

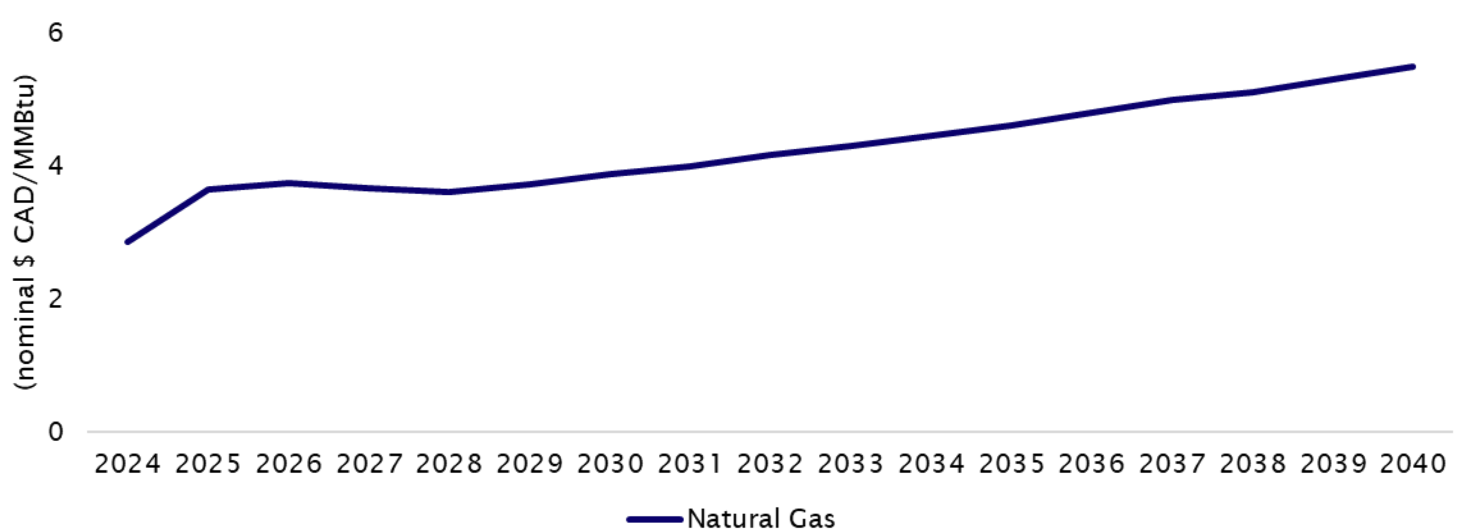
| Technology | Average EFORd (%) | Average SOF (%) |
|---|---|---|
| Combined cycle | 4 | 10 |
| Coal | 11 | 14 |
| Internal combustion engine | 12 | 7 |
| Multi-turbine | 14 | 16 |
| Steam turbine | 11 | 14 |
| Gas turbine | 12 | 7 |

- Equivalent Forced Outage Rate on demand ("EFORd"): measures the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate
- Scheduled Outage Factor ("SOF"): a measure of the unit's unavailability due to planned or maintenance outages

# LEI developed and applied its own proprietary gas price forecast for AECO Hub in this modeling exercise

- **In the near term (2024-2028), LEI uses AECO Hub traded forwards sampled in Q3 2023 for its forecast of gas prices**
  - Near-term forwards range from $2.87/MMBtu in 2024 to $3.74/MMBtu in 2026
  - This is a decline from the very high prices in 2022, which reflected the uncertainty over gas supplies in Europe owing to embargos on Russian pipeline gas
- **In the long term (2029-2040), LEI relies on the Canadian Energy Regulator ("CER")'s 2021 long term outlook**
  - LEI has been using CER's 2021 outlook since December 2021 and believes that the CER's "Current Policies" case is still a reasonable baseline AECO outlook
- **LEI then estimated monthly prices for each year consistent with historical patterns**

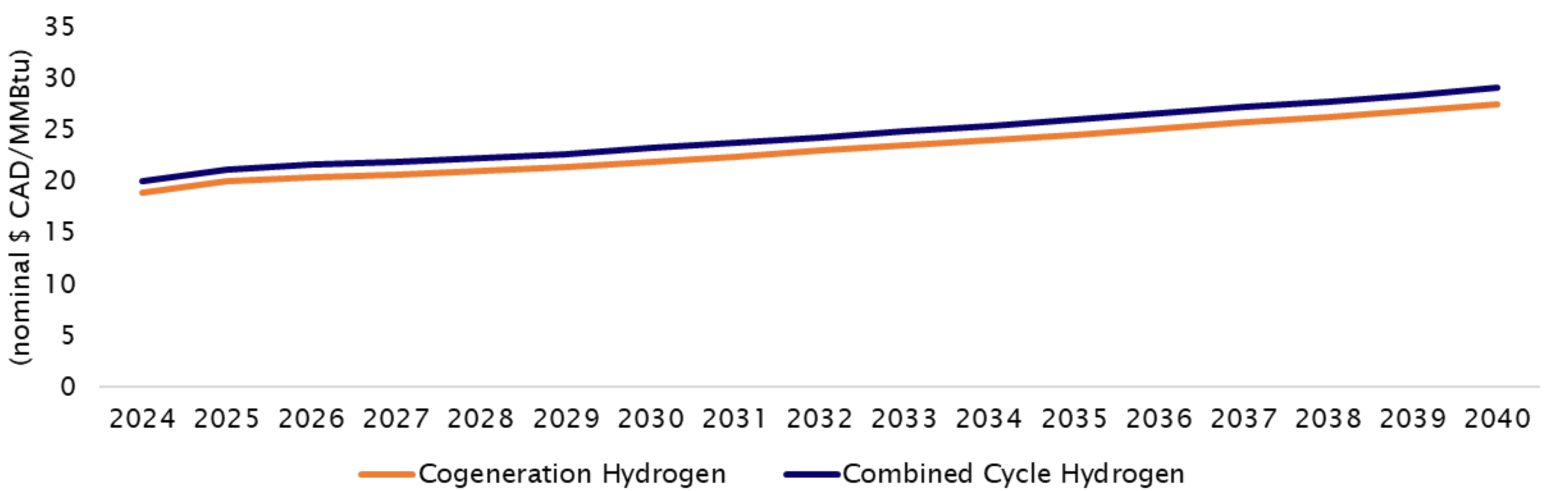
**LEI gas price forecast (2024-2040)**



# LEI developed two hydrogen fuel price forecasts to account for the different characteristics of hydrogen technologies reflected in AESO's supply forecast

- **Different production processes for blue hydrogen have cost implications on the overall hydrogen price**
  - Cogeneration hydrogen is assumed to be produced via autothermal reforming ("ATR") on-site – i.e., ATR is co-located with electricity production
  - For combined cycle hydrogen, it is assumed that blue hydrogen would be purchased from a centrally produced area rather than be produced on-site
  - Therefore, LEI assumes transportation costs for the combined cycle hydrogen unit and no transportation costs for the co-located cogeneration unit
- **All operational characteristics, including fixed and variable costs of hydrogen production, are based on publicly available NREL models for hydrogen technologies**
- **LEI adapted these models to more accurately reflect the local context by using Alberta natural gas as the feedstock**
  - Consequently, hydrogen gas prices will vary and track Alberta's natural gas prices

**LEI hydrogen price forecast (2024-2040)**



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# LEI's carbon policy assumptions rely on various public sources, including AESO's preliminary 2024 LTO projections and current federal/provincial regulations

- **Consistent with the federal carbon pricing system, the carbon tax starts at $85/tonne of CO2e in 2024, increasing by $15/tonne increments each year and leveling off at $170/tonne in 2030; carbon tax assumptions are held constant across all modeled scenarios**
  - After 2030, LEI applies a more modest inflationary annual increase of 2% to the price of carbon, consistent with AESO's assumptions in the preliminary 2024 LTO

- **Technology Innovation and Emissions Reduction ("TIER") emissions performance standards across the 2035 and 2050 decarbonization scenarios are different**
  - Under the 2035 decarbonization scenario, the emissions performance standard is set to decline from 0.3552 tonnes/MWh in 2024 to 0 tonnes/MWh by 2035
  - In contrast, the 2050 decarbonization scenario sees the emissions performance standard decline from 0.3552 tonnes/MWh in 2024 to 0 tonnes/MWh by 2050

| High Performance Benchmark Assumptions | Unit | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Decarbonization by 2050 | t/MWh | 0.36 | 0.35 | 0.34 | 0.33 | 0.33 | 0.32 | 0.31 | 0.30 | 0.28 | 0.26 |
| Decarbonization by 2035 | t/MWh | 0.36 | 0.35 | 0.34 | 0.33 | 0.33 | 0.32 | 0.31 | 0.25 | 0.19 | 0.12 |
| **High Performance Benchmark Assumptions** | **Unit** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** |
| Decarbonization by 2050 | t/MWh | 0.25 | 0.23 | 0.22 | 0.20 | 0.19 | 0.17 | 0.16 | 0.14 | 0.12 | 0.11 |
| Decarbonization by 2035 | t/MWh | 0.06 | - | - | - | - | - | - | - | - | - |

## LEI's approach to the draft federal Clean Electricity Regulations ("CER")

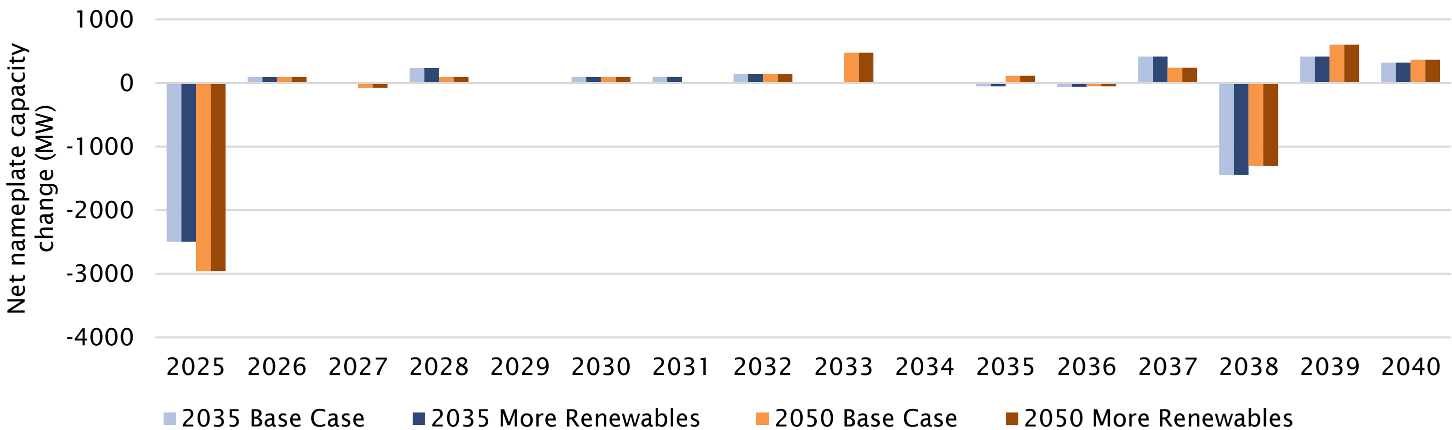
- According to the draft CER, the proposed regulations apply to all electricity generation units that meet the applicability criteria:
  a. has an electricity generation capacity of 25 MW or more;
  b. generates electricity using fossil fuel; and
  c. is connected to an electricity system that is subject to NERC standards
- Existing units commissioned before January 1, 2025 are expected to align with the performance emissions standard by whichever comes first – January 1, 2035, or "following the unit's end of prescribed life," which is defined as 20 years after its commissioning date
- New units that come into operation after January 1, 2025 will be required to meet the performance standard by January 1, 2035
- By 2035, unabated gas-fired units that have a generation capacity of 25 MW or more will be limited to operating 450 hours/year, ~5% of the plant's operating capacity
- Units below 25 MW are exempt from the draft CER

# Additional technical assumptions and operating parameters are based on publicly available data and industry-standard assumptions

- **Other technical assumptions (heat rates, minimum stable generation ("MSG") levels, minimum on and off times, etc.) were developed by LEI for purposes of its multi-client forward price outlook, leveraging well-accepted industry data**
  - Heat rate curves estimated from historic hourly generation and offer data published by AESO and cross-referenced with data from similar technology/vintage plants in the US (sourced from EIA, EPA, FERC)
  - MSG levels implied from historical hourly generation data and offer data published by AESO
  - Minimum on/off hours based on energy merit order offer patterns/generation data patterns
- **Some price responsive load ("PRL") is included in the modeling**
  - Based on data published by the MSA, approximately 300-500 MW of load foregoes consumption of electricity when Pool Prices increase
  - These levels of PRL are also consistent with information released over the years by the major industrial trade associations in Alberta regarding their members' direct participation in the energy market
- **Imports are represented as virtual supply (with import volumes based on pricing outcomes); exports are represented as virtual demand (based on historical patterns and also related to pricing outcomes)**
  - Levels of imports and exports are determined hourly based on Pool Price – higher priced hours are observed to have more imports and lower priced hours have more exports
  - Maximum import available transfer capability ("ATC") over the forecast period is expected to increase by 388 MW by 2030 following intertie restorations
  - Exports were developed by analyzing the historical export quantity correlation with the Mid-C implied market heat rate, the modeled export quantity is based on the forecasted Mid-C gas price

# Thermal net new entry across both 2035 and 2050 scenarios is limited due to a significant level of retirements

Net annual non-renewable entry, 2035 and 2050 scenarios

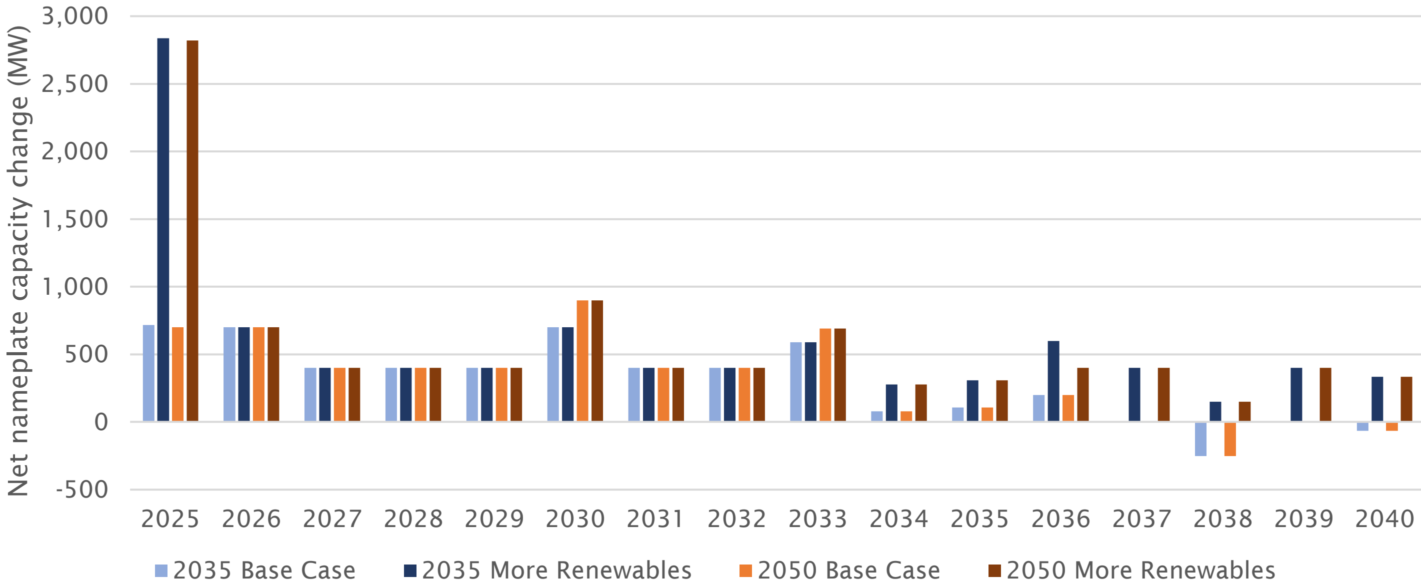



Note: Non-renewable entry in this case is inclusive of retrofitted CCGT with CCS units and hydrogen units.

- **Thermal installed capacity in the 2050 scenarios is lower than the 2035 scenarios from 2025 to 2038**
  - The 2050 case sees the retirement of 2,566 MW of coal-to-gas units in 2024; 395 MW more than the 2035 scenarios
- **Net additions in the late 2020s and early 2030s are driven by cogen and cogen hydrogen new entries**
- **Post-2037, the 2035 scenarios see more capacity additions of combined cycle hydrogen units, approximately 1,255 MW more capacity than the 2050 scenarios by 2040**
- **The limited combined cycle hydrogen capacity is offset by new CCGT and simple cycle additions in the 2050 scenarios**
- **Projected new resource additions are subject to significant technological risks**
  - LEI relies on AESO's preliminary 2024 LTO supply mix assumptions, which incorporate new generation technologies (e.g., hydrogen-based generation, natural gas-fired generators retrofitted with carbon capture technologies, and SMRs)
  - LEI took these assumptions as given and did not consider the investment risk hurdles involved in the development of these technologies (i.e., cost overruns, delays, and other construction, financing, and operating risks)

# Solar and wind new entry are similar across the 2035 and 2050 Base Cases over the longer term

Net annual renewable entry, 2035 and 2050 scenarios




- **Wind capacity is 300 MW higher in the 2050 scenarios due to an additional 200 MW of new entry in 2030, and an additional 100 MW of new entry in 2033 (consistent with AESO's LTO)**
  - In 2038 and 2040, AESO projects net retirement of wind and solar capacity, leading to negative MW change
- **Renewables in the near-term are based on AESO's November 2023 LTA Report**
  - New additions factor in projects in the interconnection queue that have received regulatory approval from the AUC
  - The shortfall in capacity is then added on top of AESO's generic additions
- **Under the More Renewables Cases, additions in the long-term of 200 MW are consistent with the AESO's approach for long-term additions**

# Agenda

| | |
|---|---|
| 1 | Modeling approach |
| 2 | Key assumptions and inputs |
| **3** | **Key modeling results** |

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# Agenda

**3** **Key modeling results**

**Implications of different decarbonization policies**

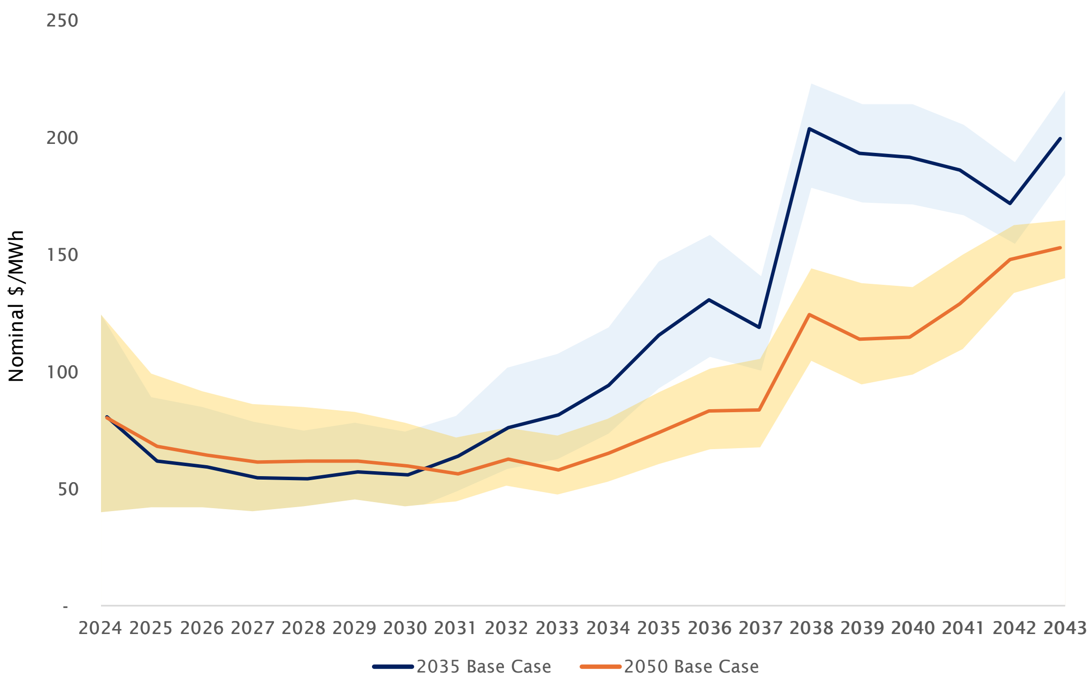
Implications of additional renewables

Implications of lower demand

# Pool Prices under the 2050 Base Case are lower than under the 2035 Base Case from 2031 onwards, largely due to the impact of less stringent carbon emissions performance standards

- **Under LEI's 2035 Base Case, average Pool Prices grow from an average of $81/MWh in 2024 to $200/MWh by 2043 under 'weather normal' conditions**
  - Pool Prices rise after 2030 due to tight supply-demand conditions, higher carbon costs, and hydrogen prices
- **LEI's 2050 Base Case demonstrates a more modest increase in Pool Prices: from an average of $80/MWh in 2024 to $153/MWh by 2043 under 'weather normal' conditions**
  - Considering less stringent conditions to achieve net zero under the 2050 scenario, the replacement of existing technologies with cleaner but more expensive technologies (like hydrogen) occurs gradually; thus, price increases are gradual

**Annual average Pool Price forecast for LEI's Base Cases (weather normal)**




For the 20-year forecasts, LEI ran its simulation model 10 times (seeds), with randomized forced outages and maintenance schedules, which resulted in a range of Pool Price outcomes. The shaded areas represent the range of annual average Pool Price outcomes modeled by LEI, and the solid lines represent the average of the 10-seed results under each Base Case.

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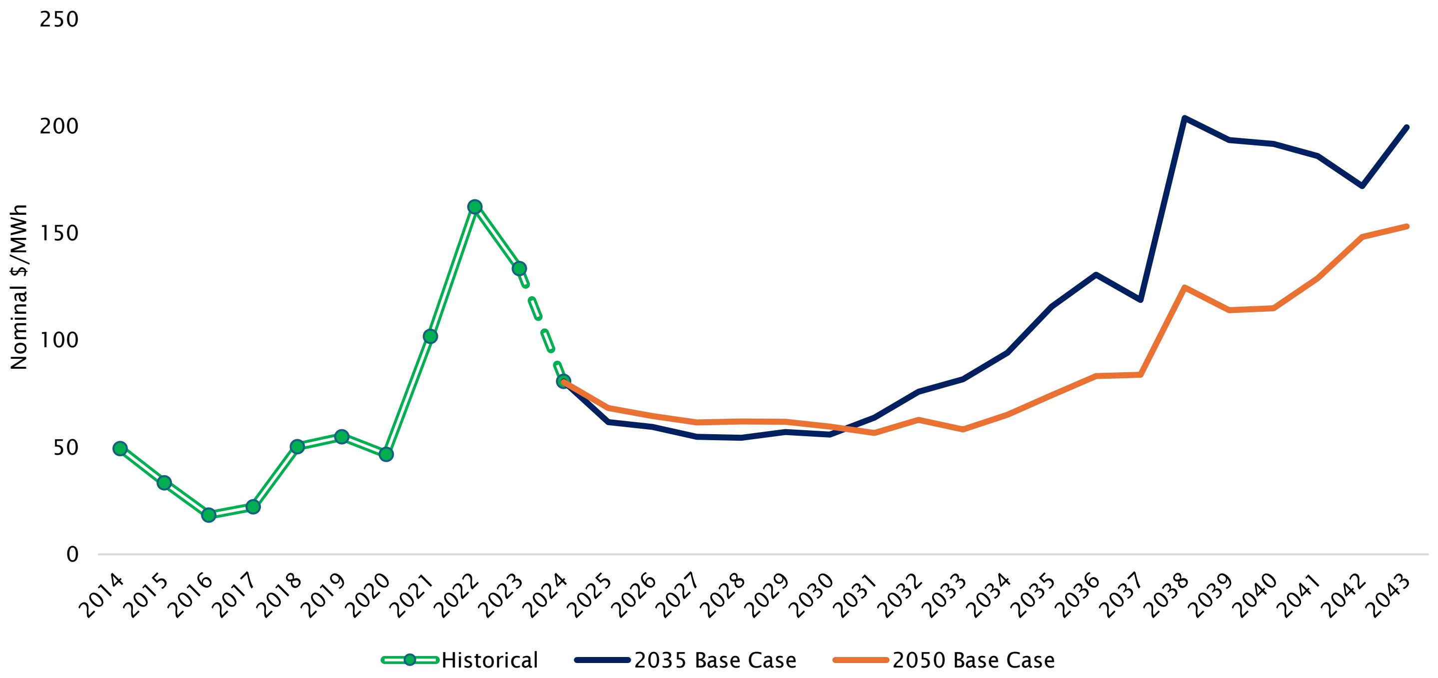
# Pool Prices are expected to reach their highest forecasted levels in 2038 under the 2035 Base Case, higher than Pool Prices reached in 2022

- **In the near- to mid-term, forecasted Pool Prices under both Base Cases are lower than historical average Pool Prices recorded in 2021-2023**
  - Significant generation investment is expected to increase supply and put downward pressure on Pool Prices in the near-term
  - In addition, significant wind and solar new entry results in more $0/MWh priced hours, which drives Pool Prices down

**Annual average Pool Price forecast for LEI's Base Cases (weather normal) compared to historical Pool Prices**



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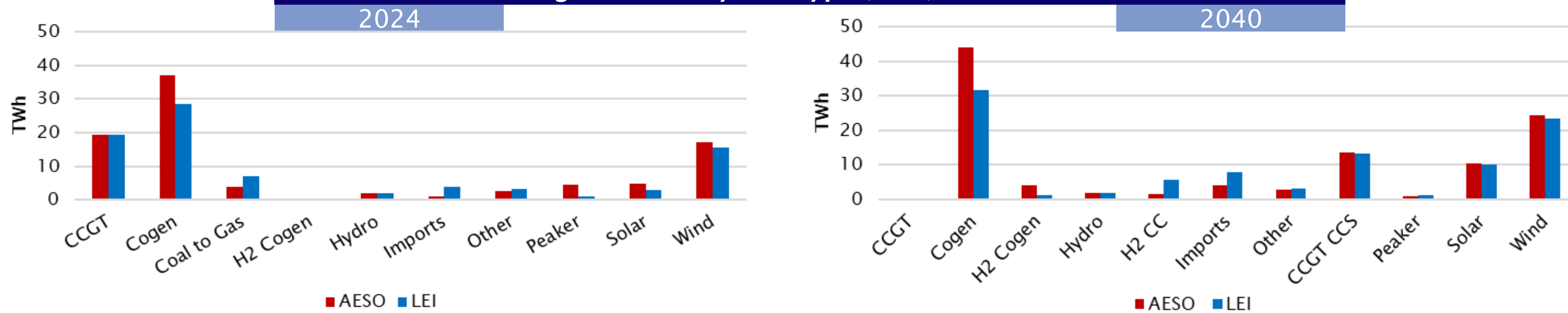
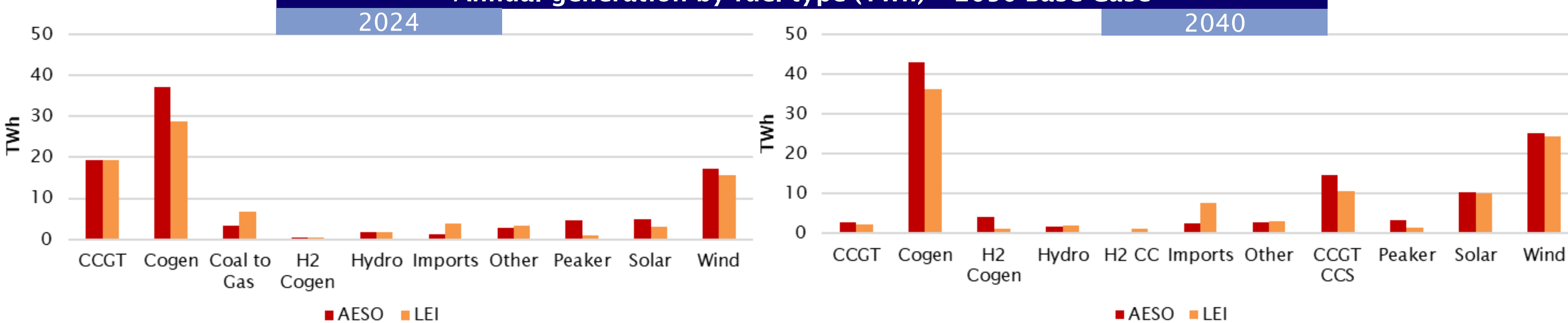
# In 2024, CCGT and cogen account for the largest share of generation; by 2040, renewable generation accounts for nearly 50% of total generation

## Annual generation by fuel type (TWh) – 2035 Base Case



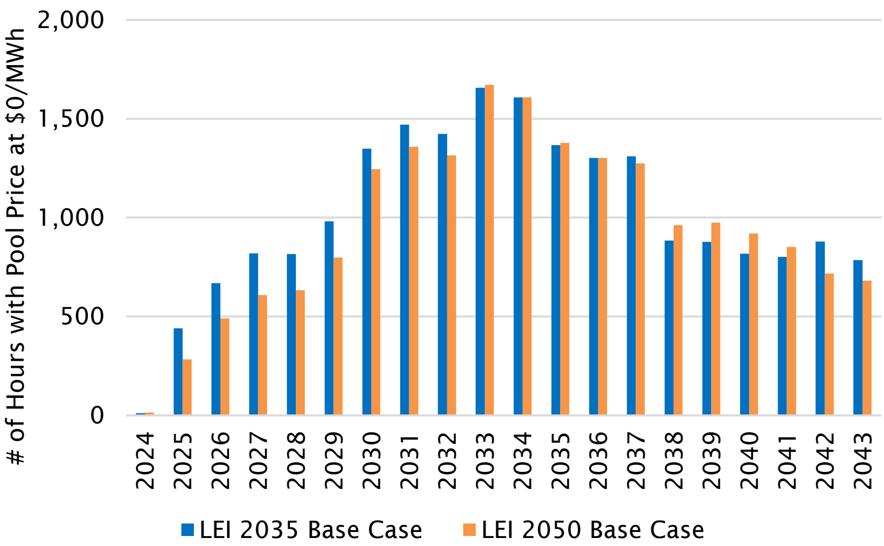

## Annual generation by fuel type (TWh) – 2050 Base Case



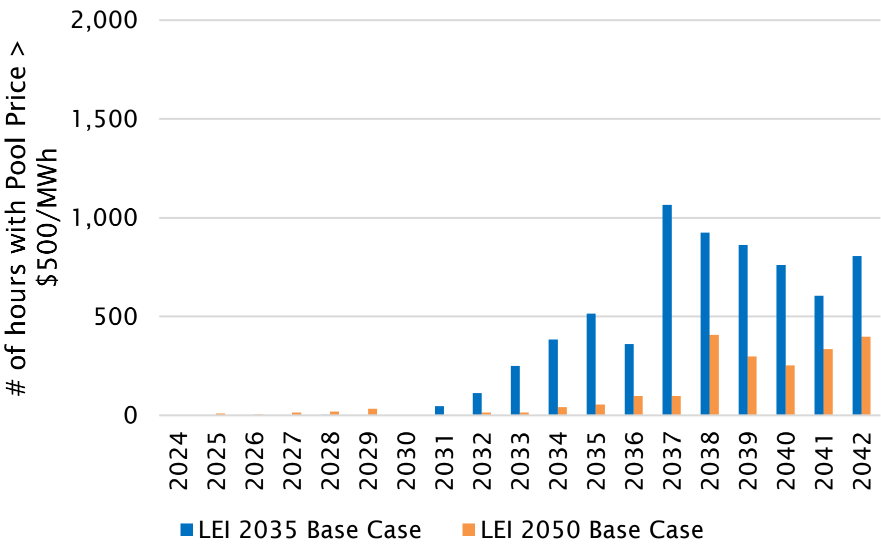

- **Less stringent emissions performance standards allow for slightly higher unabated gas unit operations in the 2050 Base Case**
  - Under the 2035 Base Case, by 2040, there is no CCGT without CCS, while the 2050 Base Case has a few units still generating
  - Similarly, for peakers, annual generation under the 2050 Base Case is slightly higher than the 2035 Base Case
- **LEI's and AESO's projected energy mix is generally aligned**
  - In 2024, LEI modeled more output from coal-to-gas units and others – the generation in the "others" category includes biomass, demand response, and coal (just for 2024); in 2040, the difference in cogen output is largely offset by LEI's output from imports and CCGT with CCS

# Pattern of zero priced hours is similar across the 2035 and 2050 Base Cases, but there are more instances of price spikes (>$500/MWh) in the 2035 Base Case

## Frequency of zero prices




## Frequency of Pool Prices > $500/MWh




- **Frequency of zero prices is higher in the 2035 Base Case in the early years (before 2038) because the 2035 Base Case has more coal-to-gas units, which have high minimum stable generation that offers at $0/MWh**
  - This trend reverses after 2038, when all coal-to-gas units retire in both cases. After 2038, the 2050 Base Case has slightly more wind, which results in more $0/MWh hours than the 2035 Base Case
- **Frequency of Pool Prices greater than $500/MWh is significantly higher in the 2035 Base Case than the 2050 Base Case**
  - Price spikes occur due to a combination of factors, including higher short-run marginal costs from hydrogen and CCGT with CCS in the 2035 Base Case, and more economic withholding in years where the 2035 Base Case has more coal-to-gas units online than the 2050 Base Case

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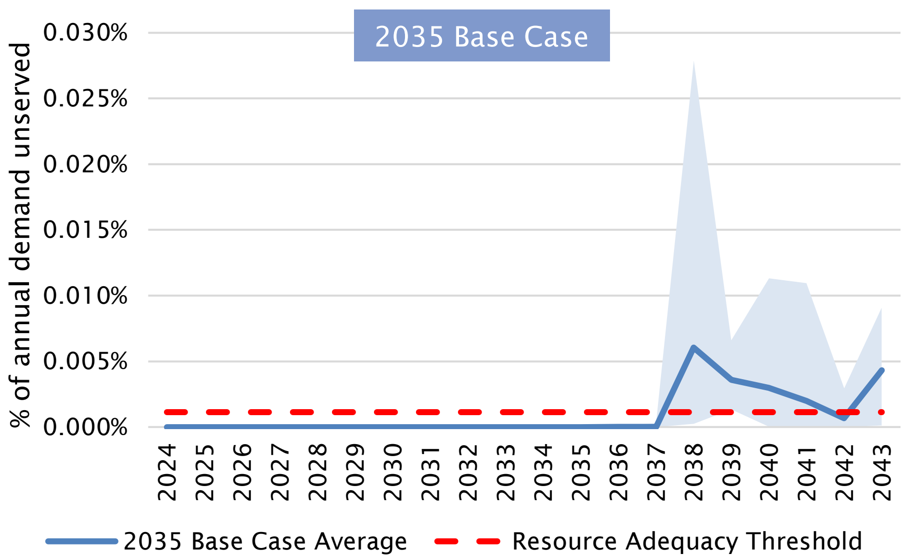
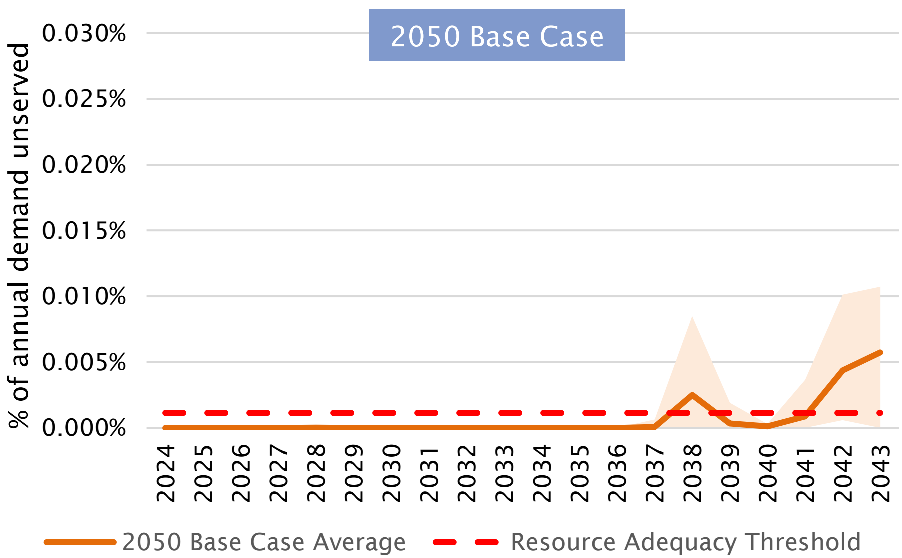
# Alberta's electricity system becomes significantly less reliable after 2037 – even without factoring in weather impacts – due to the retirement of all remaining coal-to-gas units (in both the 2035 and 2050 Base Cases)

## % of annual demand unserved (10-seed average, weather normal conditions)




- **Shaded regions indicate the range of demand unserved (as % of annual demand) across the different seeds (reflecting varying generation outage patterns), while the solid lines reflect the average demand unserved (as % of annual demand)**
- **By the late 2030s, reliability risk under the 2035 Base Case is expected to be worse than the 2050 Base Case**
- **However, under both cases, the level of reliability by the late 2030s would be at a level materially worse than what Albertans have been accustomed to, as indicated by the modeled unserved energy crossing above the AESO's Resource Adequacy Threshold**

Note: AESO defines the Resource Adequacy Threshold as the 1-hour average Alberta internal load for a year divided by 10. Converting to percentage terms is calculated as 1/8760/10 = 0.00114%.

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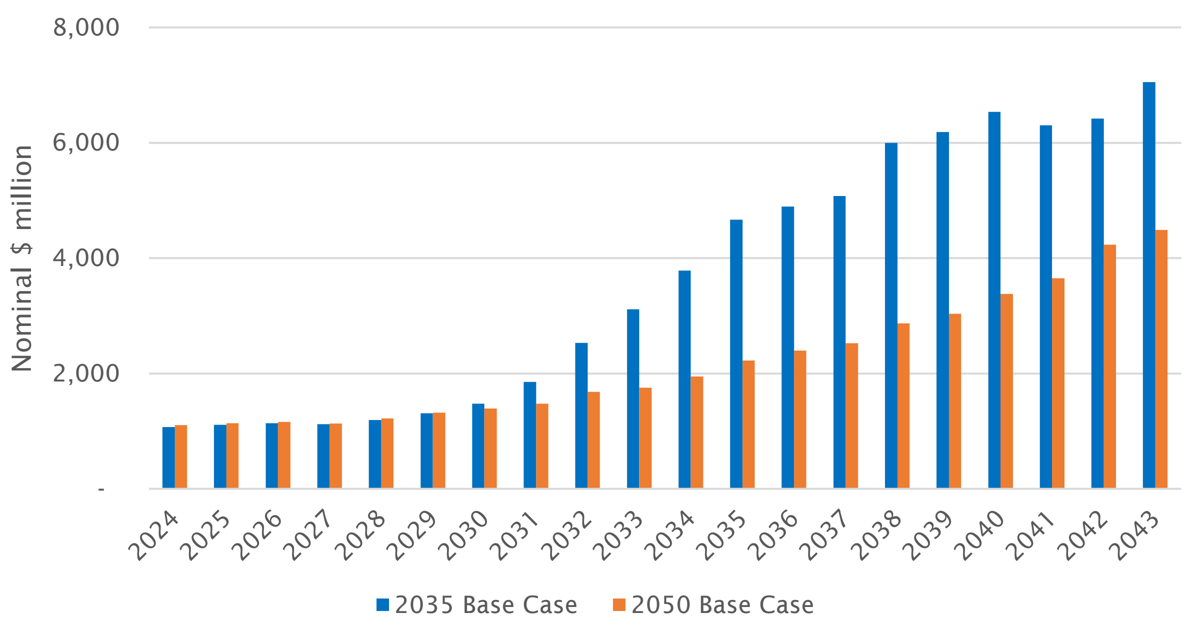
# Decarbonization policy choice can lead to significant differences in production costs after 2030: 2035 Base Case has significantly higher variable costs of electricity generation than the 2050 Base Case

- **From 2024 to 2043, total production cost (sum of fuel costs + variable O&M cost + carbon cost of all units) for the 2035 Base Case averages 65% higher than the 2050 Base Case**
  - The difference between the two cases is the largest in 2035, where the 2035 Base Case total production cost is 109% higher than the 2050 Base Case
- **This is largely due to differences in carbon policy – while the nominal carbon tax price is the same, the amount that a fossil-based generator needs to pay is higher in the 2035 Base Case, due to more stringent emissions performance standards**

**Total production cost (2035 Base Case vs 2050 Base Case, nominal $ million)**



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# LEI monitored the simulated profits of resources to assess the economic viability of both new generation projects and existing assets

- For new entry, LEI considered the investment decision and monitored the return on invested capital, as well as ongoing operations, and sufficiency of gross profits to cover minimum going forward fixed costs; LEI used AESO's cost assumptions for new plants

**All-in fixed cost for new generation (nominal $/kW-year)**

| Technology | 2030 | 2035 | 2040 |
|---|---|---|---|
| CCGT | 273 | - | - |
| CCGT with CCS with ITC | 412 | 456 | 504 |
| CCGT with CCS Retrofits with ITC | 214 | 317 | 354 |
| Peaker (Frame) | 164 | 181 | 200 |
| Cogeneration Hydrogen with ITC | 134 | 172 | 190 |
| Combined Cycle Hydrogen with ITC | - | - | 334 |
| Wind with ITC | 239 | 321 | 346 |
| Solar with ITC | 156 | 208 | 221 |
| Storage with ITC | 182 | 258 | 273 |

- For existing generation, LEI considered whether gross profits from the wholesale energy market are sufficient to cover minimum going forward fixed operations and maintenance

**Fixed O&M cost for existing generation (nominal $/kW-year)**

| Technology | 2030 | 2035 | 2040 |
|---|---|---|---|
| Existing CCGT | 24 | 27 | 30 |
| Coal-to-gas units | 70 | 77 | 85 |
| Existing peaker (Frame) | 12 | 13 | 15 |
| Existing cogen | 12 | 13 | 15 |
| Existing wind | 45 | 50 | 55 |
| Existing solar | 26 | 29 | 32 |
| Existing storage | 70 | 77 | 85 |

Source: All-in fixed costs based on costs reported in AESO's preliminary 2024 LTO. Fixed O&M costs for existing generation based on generic technology-level information and intentionally does not reflect precise costs for any specific operating plant in Alberta.

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# In the 2035 Base Case, new generation investment is earning low returns in the first ten years, but profitability steps up in the back years, and all new resources are generally earning enough to cover their fixed O&M costs

- **Net yield is calculated based on the gross profits earned by the resource in the energy market (revenue – SRMC), less fixed O&M costs by technology type, and compared against the net capital cost of the new entry**

***Energy market profits*** *=*

*realized energy price – (fuel price x heat rate) – variable O&M costs – carbon costs (or revenue)*

***Net yield*** *= (annual energy markets profits – fixed O&M costs) / net capital cost*

- **Assuming required return for new generation investment of 10.5% (based on AESO's nominal pre-tax WACC), most new generation capacity is under-earning in the first ten years of the forecast period, but returns improve in the later years**

**Modeled pre-tax net yield of new entry (2035 Base Case)**

| Technology | 2030 | 2035 | 2040 |
|---|---|---|---|
| **Gas-fired units** | | | |
| Newer CCGT (online in 2024) | 2% | N/A | N/A |
| Newer CCGT with CCS Retrofits with ITC | 9% | 8% | 21% |
| Older CCGT with CCS Retrofits with ITC | 4.1% | 8% | 20% |
| Peaker (Frame) | -1% | 5% | 15% |
| **Hydrogen** | | | |
| Cogeneration Hydrogen with ITC | -18% | -6% | 14% |
| Combined Cycle Hydrogen with ITC | N/A | N/A | 19% |
| **Renewables and storage** | | | |
| Wind with ITC | 14% | 5% | 11% |
| Solar with ITC | 10% | 3% | 4% |
| Storage with ITC* | -2% | 0% | 1% |

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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# Under the 2050 Base Case, gas-fired and hydrogen-based new resources face somewhat poorer economics as compared to the 2035 Base Case, due to lower Pool Prices

- **Under the 2050 Base Case, Pool Prices are lower (relative to the 2035 Base Case) for two main reasons:**
  - Less stringent carbon emissions performance, which lowers the marginal cost of gas-fired units
  - Reduced price impact from economic withholding (before all coal-to-gas retires)
- **This results in overall lower profits for new investment through 2040; gas-fired new entry and retrofitted units are projected to earn their target return (or higher) after 2040**
  - Some new investments – like hydrogen-based units – are not projected to achieve 10.5% returns within the 20-year modeled timeframe; however, under a different fuel forecast and with different operating conditions (and capital cost estimates), the financial outcomes may improve

**Modeled pre-tax net yield of new entry (2050 Base Case)**

| Technology | 2030 | 2035 | 2040 |
|---|---|---|---|
| **Gas-fired units** | | | |
| Newer CCGT (online in 2024) | N/A | 5% | 9% |
| Newer CCGT with CCS Retrofits with ITC | 10% | 5% | 9% |
| Older CCGT with CCS Retrofits with ITC | 6.1% | 2.8% | 8% |
| Peaker (Frame) | 0% | 1% | 5% |
| **Hydrogen** | | | |
| Cogeneration Hydrogen with ITC | -17% | -15% | -8% |
| Combined Cycle Hydrogen with ITC | N/A | N/A | 2% |
| **Renewables and storage** | | | |
| Wind with ITC | 15% | 9% | 11% |
| Solar with ITC | 11% | 7% | 6% |
| Storage with ITC* | -2% | -1% | -1% |

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

# Agenda

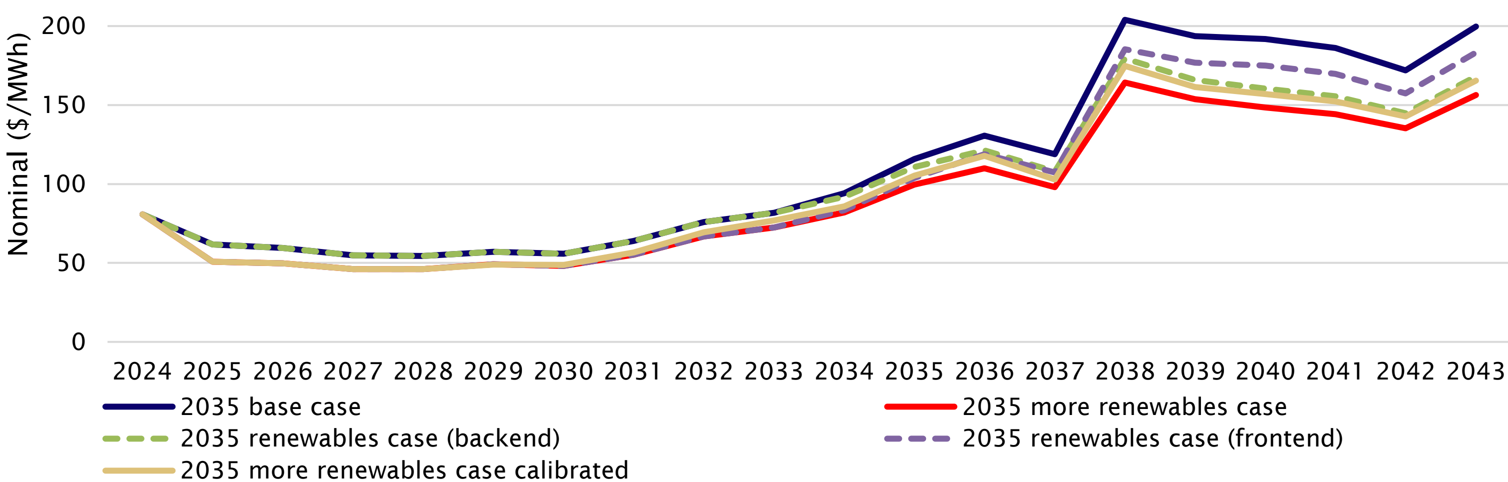
| | |
|---|---|
| 3 | **Key modeling results** |

- Implications of different decarbonization policies
- **Implications of additional renewables**
- Implications of lower demand

# Additional renewable generation puts downward pressure on annual average Pool Prices in the longer term, requiring further evaluation of the impact of more renewables on other generation investment

- **Additional renewable generation reduces annual average Pool Prices, especially in the later years of the forecast**
  - By 2040, Pool Prices under the 2035 Base Case reach $192/MWh (CAGR of 4.6% from 2024); adding 4,520 MW of renewables drives down Pool Prices to $149/MWh by 2040 under the 2035 More Renewables Case (CAGR of 3.4% from 2024)
- **The reduction in Pool Prices reduces the economics of some new CCGTs and CCGT with CCS retrofits (see next few slides); LEI modified new entry/retrofits to arrive at the "Calibrated" More Renewables Case**
  - 156 MW of CCGT, instead of retrofitting with CCS, would retire in 2030 – this pushes Pool Prices back up in the 2030s, allowing other resources to return to similar levels of profitability as under the 2035 Base Case

**Annual average Pool Price for the 2035 Base Case and 2035 More Renewables Cases (nominal $/MWh)**



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# Modeling results of the 2035 More Renewables Case indicate that retrofitting CCGTs with CCS may not be economically viable for some older CCGTs; older CCGTs may choose to retire early instead of retrofitting

- **Additional renewables result in lower Pool Prices, including more frequent zero Pool Prices, which leads to lower profitability for gas- and hydrogen-fired new entry**
- ***Without* additional renewables, older CCGTs with CCS retrofits can cover their fixed O&M costs in 7 out of 10 years in 2028-2037**
- ***With* additional renewables, older CCGTs with CCS retrofits are only marginally able to recover their fixed O&M costs in 2028-2032, and their profitability continues to be much lower (relative to the 2035 Base Case) through the late 2030s**
  - Such economic returns may suggest the possibility of a different longer term market outcome, where some of the older CCGTs may choose to retire instead of retrofitting with CCS – this forms the basis of developing the More Renewables Calibrated Case

**Modeled pre-tax net yield of new entry (2035 More Renewables Case)**

| Technology | 2030 | 2035 | 2040 |
|---|---|---|---|
| **Gas-fired units** | | | |
| Newer CCGT (online in 2024) | 1% | N/A | N/A |
| Newer CCGT with CCS Retrofits with ITC | 8% | 6% | 14% |
| Older CCGT with CCS Retrofits with ITC | 3% | 6% | 14% |
| Peaker (Frame) | -1% | 4% | 11% |
| **Hydrogen** | | | |
| Cogeneration Hydrogen with ITC | -19% | -9% | 4% |
| Combined Cycle Hydrogen with ITC | N/A | N/A | 11% |
| **Renewables and storage** | | | |
| Wind with ITC | 13% | 3% | 6% |
| Solar with ITC | 8% | 1% | 0% |
| Storage with ITC* | -2% | 0% | 1% |

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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# With more renewables layered on top of the 2035 Base Case, if one existing CCGT decides to retire instead of retrofit with CCS, Pool Prices would increase, improving the profitability of other units

- **LEI tested retiring one CCGT and two CCGTs to understand how the economics of other units would be impacted, and found that retiring two CCGTs would bring the economics of other units to be over the 2035 Base Case levels**
- **The increase in Pool Price is caused by both high prices due to changes in merit order, but also worse reliability (due to the decrease in CCGT fleet size)**
- **Retiring one CCGT in 2030 would change the economics of the remaining CCGTs with CCS retrofits – they would go from having a negative net present value ("NPV") to positive NPV**
  - NPV is calculated based on the sum of discounted net profits throughout the forecast period using a 10.5% discount rate

**Modeled pre-tax net yield of new entry (2035 More Renewables Calibrated Case)**

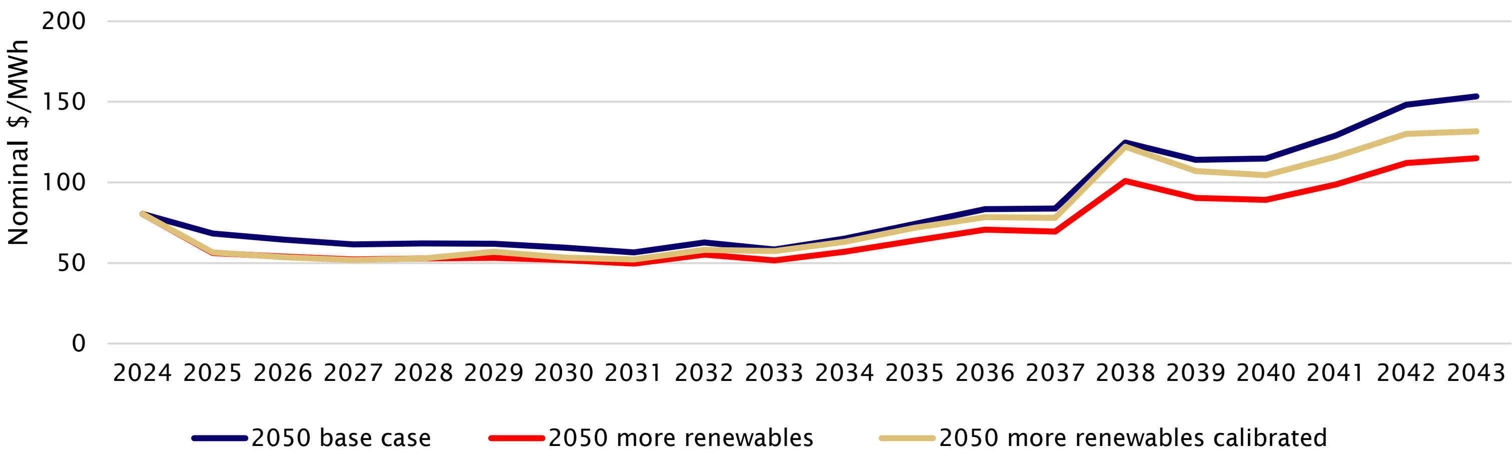
| Technology | 2030 | 2035 | 2040 |
|---|---|---|---|
| **Gas-fired units** | | | |
| Newer CCGT (online in 2024) | 1% | N/A | N/A |
| Newer CCGT with CCS Retrofits with ITC | 8% | 7% | 16% |
| Older CCGT with CCS Retrofits with ITC | 3% | 8% | 16% |
| Peaker (Frame) | -1% | 5% | 13% |
| **Hydrogen** | | | |
| Cogeneration Hydrogen with ITC | -19% | -7% | 8% |
| Combined Cycle Hydrogen with ITC | N/A | N/A | 14% |
| **Renewables and storage** | | | |
| Wind with ITC | 13% | 3% | 6% |
| Solar with ITC | 8% | 1% | 0% |
| Storage with ITC* | -2% | 0% | 1% |

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

# Additional renewables have a bigger price effect on annual average Pool Prices in the longer term under the 2050 Base Case

- **Under the 2050 Base Case, Pool Prices grow from an average of $80/MWh in 2024, to an average of $153/MWh by 2043 (CAGR of 3.3% from 2024)**
  - 4,520 MW of additional renewable capacity drives down Pool Prices by $38/MWh by 2043, resulting in a CAGR of only 1.8% under the 2050 More Renewables Case
- **Calibrating new entry (by cancelling 125 MW of new entry) increases Pool Prices closer to the 2050 Base Case**
  - Average Pool Prices at the end of the forecast timeframe increase from $115/MWh under the 2050 More Renewables Case to $132/MWh under the 2050 More Renewables Calibrated Case
- **The system is more sensitive to supply changes in the 2050 More Renewables Case, as the system is less reliable in the back-end (2040+) as compared to the 2035 More Renewables Case**

**Annual average Pool Price for the 2050 Base Case and 2050 More Renewables Cases (nominal $/MWh)**



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# Testing of the 2050 More Renewables Case indicates that 125 MW of gas-fired units may not be economically sustainable, due to the resulting Pool Price impacts of additional renewable generation

- **More Renewables layered on top of the 2050 Base Case puts further pressure on the economics of gas-fired units**
  - Many new or retrofitted CCGTs are only able to cover their fixed O&M costs – even by the late 2030s
  - Older CCGTs with CCS retrofits are only marginally able to recover their fixed O&M costs over an extended timeframe (during the 2033-2037 period)
  - Hydrogen-based units are not able to earn a positive return on investment even by the end of the 20-year forecast period

**Modeled pre-tax net yield of new entry (2050 More Renewables Case)**

| Technology | 2030 | 2035 | 2040 |
|---|---|---|---|
| **Gas-fired units** | | | |
| Newer CCGT (online in 2024) | N/A | 3% | 5% |
| Newer CCGT with CCS Retrofits with ITC | 8% | 3% | 6% |
| Older CCGT with CCS Retrofits with ITC | 5% | 2% | 5% |
| Peaker (Frame) | 0% | 1% | 4% |
| **Hydrogen** | | | |
| Cogeneration Hydrogen with ITC | -18% | -16% | -13% |
| Combined Cycle Hydrogen with ITC | N/A | N/A | -1% |
| **Renewables and storage** | | | |
| Wind with ITC | 13% | 8% | 7% |
| Solar with ITC | 8% | 5% | 3% |
| Storage with ITC* | -2% | -1% | -1% |

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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# Cancelling 125 MW of new entry in 2029-2033 brings the profitability of other units back to the 2050 Base Case levels

- CCGTs with CCS retrofits are not able to earn a reasonable rate of return in all 2050 cases due to the low carbon price
- Cancelling 125 MW of new entry only helps bring the net yield of CCGT with CCS retrofits to be non-negative and similar to 2050 Base Case levels
- Even though the profitability of new entry improves under the 2050 More Renewables Calibrated Case, levels are still lower than those in the 2035 Base Case and 2035 More Renewables Calibrated Case

**Modeled pre-tax net yield of new entry (2050 More Renewables Calibrated Case)**

| Technology | 2030 | 2035 | 2040 |
|---|---|---|---|
| **Gas-fired units** | | | |
| Newer CCGT (online in 2024) | N/A | N/A | 8% |
| Newer CCGT with CCS Retrofits with ITC | 9% | 5% | 9% |
| Older CCGT with CCS Retrofits with ITC | 5% | 4% | 8% |
| Peaker (Frame) | 0% | 2% | 6% |
| **Hydrogen** | | | |
| Cogeneration Hydrogen with ITC | -18% | -14% | -7% |
| Combined Cycle Hydrogen with ITC | N/A | N/A | 3% |
| **Renewables and storage** | | | |
| Wind with ITC | 14% | 8% | 8% |
| Solar with ITC | 9% | 5% | 3% |
| Storage with ITC* | -2% | -1% | 0% |

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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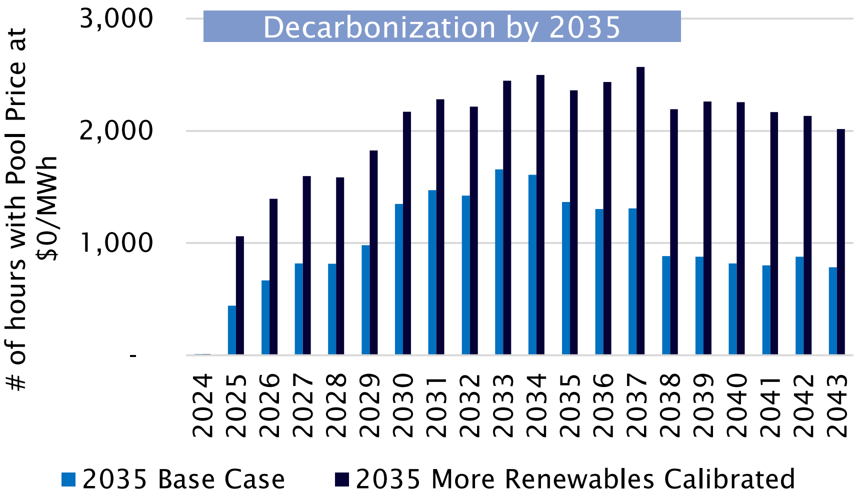
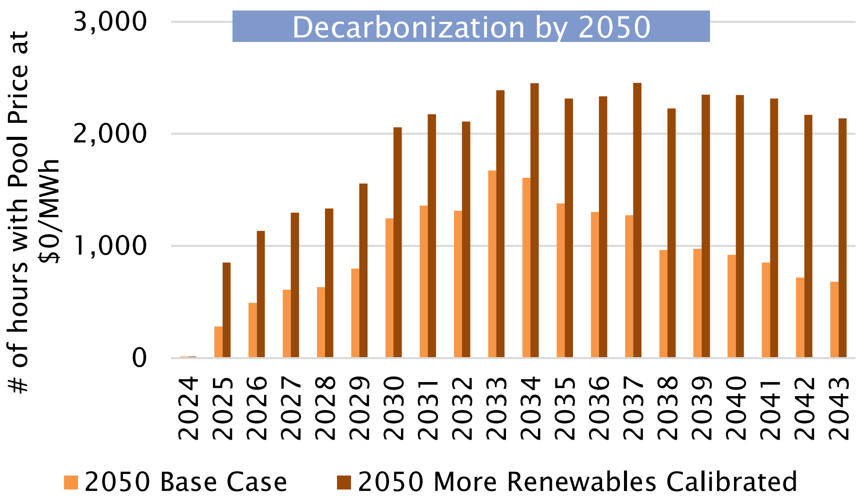
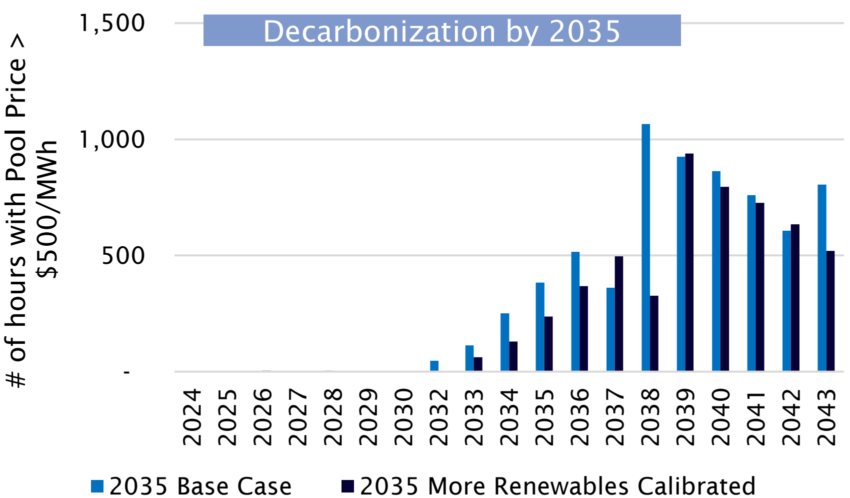
# More Renewables Calibrated Cases have significantly more hours at $0/MWh than the Base Cases, which outweighs the impact of more frequent price spikes and unserved load events in the back years

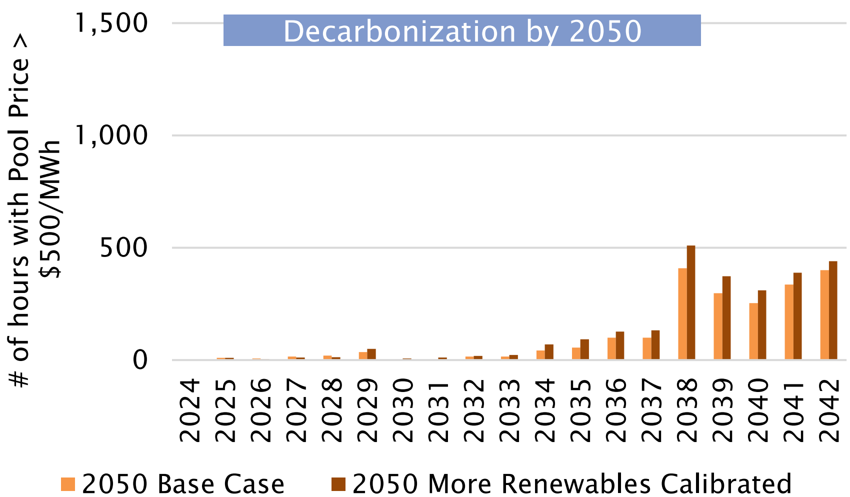
## # of hours with Pool Prices at $0/MWh (Base Case vs More Renewables Calibrated Case)



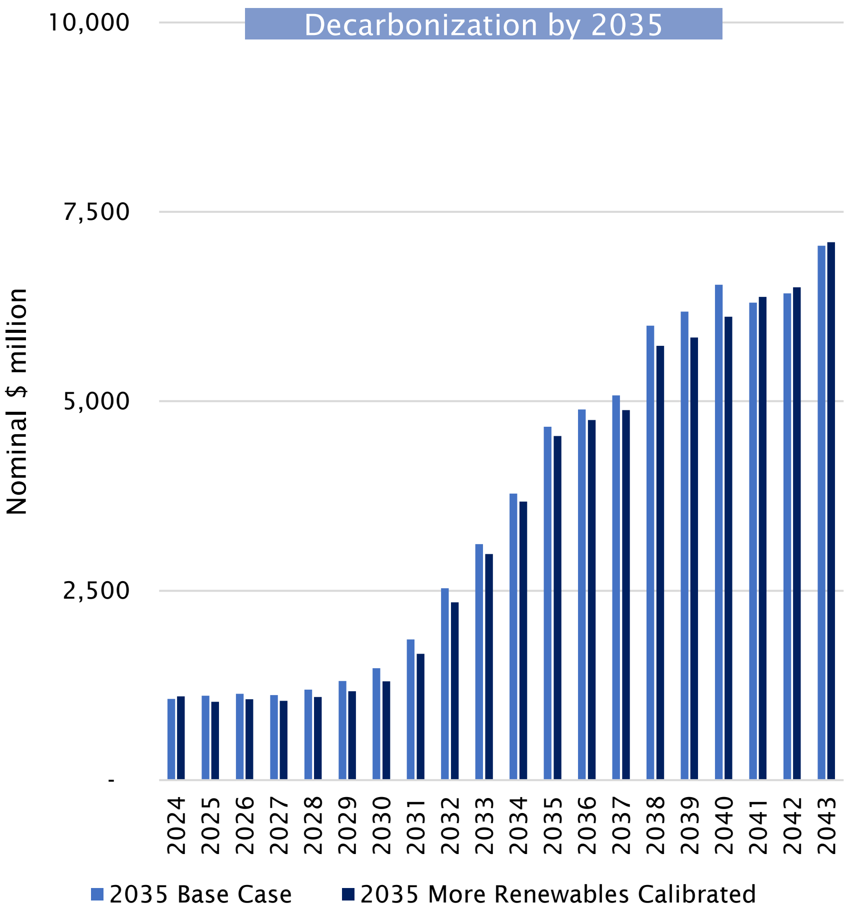

## # of hours with Pool Prices > $500/MWh (Base Case vs More Renewables Calibrated Case)

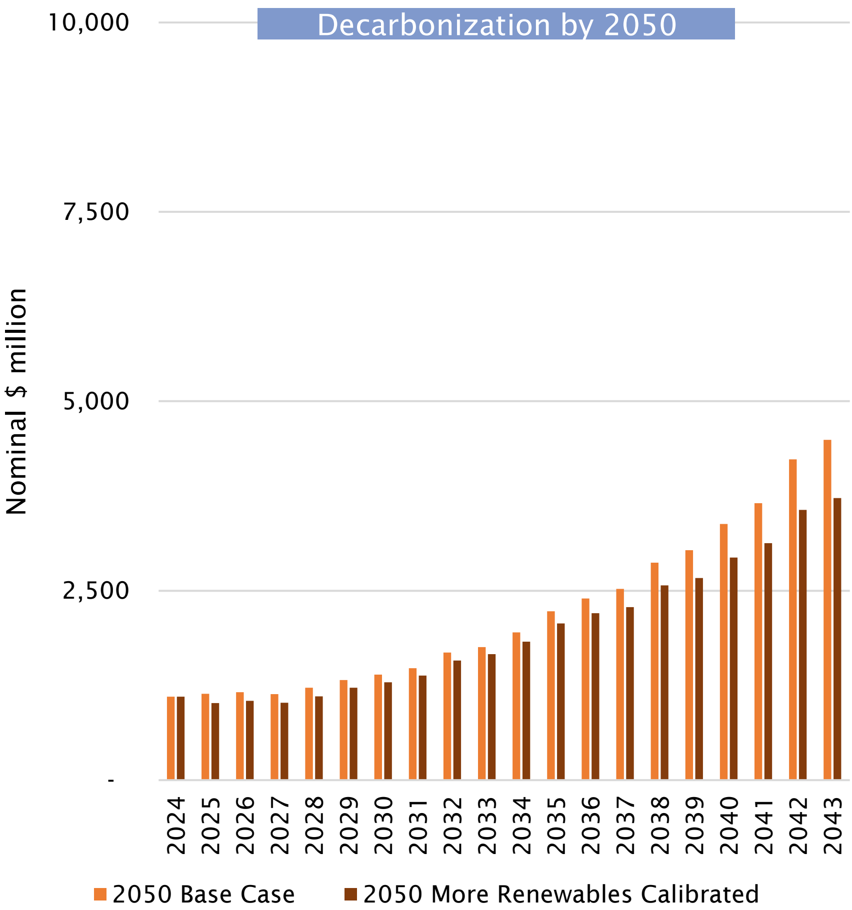


# Total production costs (sum of fuel costs + variable O&M cost + carbon cost of all units) are lower with more renewables

## Total production cost (Base Case vs More Renewables Calibrated Case, nominal $ million)



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# Agenda

**3** **Key modeling results**

Implications of different decarbonization policies

Implications of additional renewables

**Implications of lower demand**

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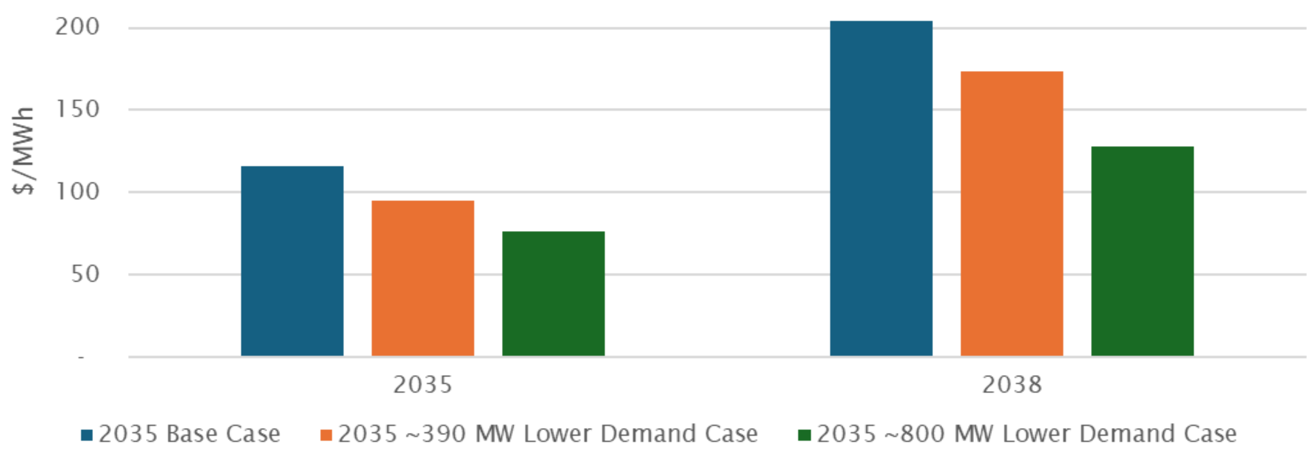
# Under the 2035 Base Case conditions, average Pool Prices are sensitive to demand shocks and fall by a much greater percentage than the change in demand

- **The purpose of the Lower Demand Cases is to understand how Pool Prices and supply adequacy change in response to a demand shock**
  - The demand shock is assumed to be unexpected; therefore, LEI kept the supply mix unchanged
  - LEI modeled the lower demand in two sample years (2035 and 2038)
- **When hourly demand is lowered by 3.5% in the ~390 MW Lower Demand Case, average Pool Prices decrease by 15% to 18%**
- **When hourly demand is lowered by 7.2% in the ~800 MW Lower Demand Case, prices are 34% to 37% lower**
- **The relatively large average Pool Price changes indicate that there are many hours where the market clears at the steeper part of the supply curve, reflecting tight supply-demand conditions**

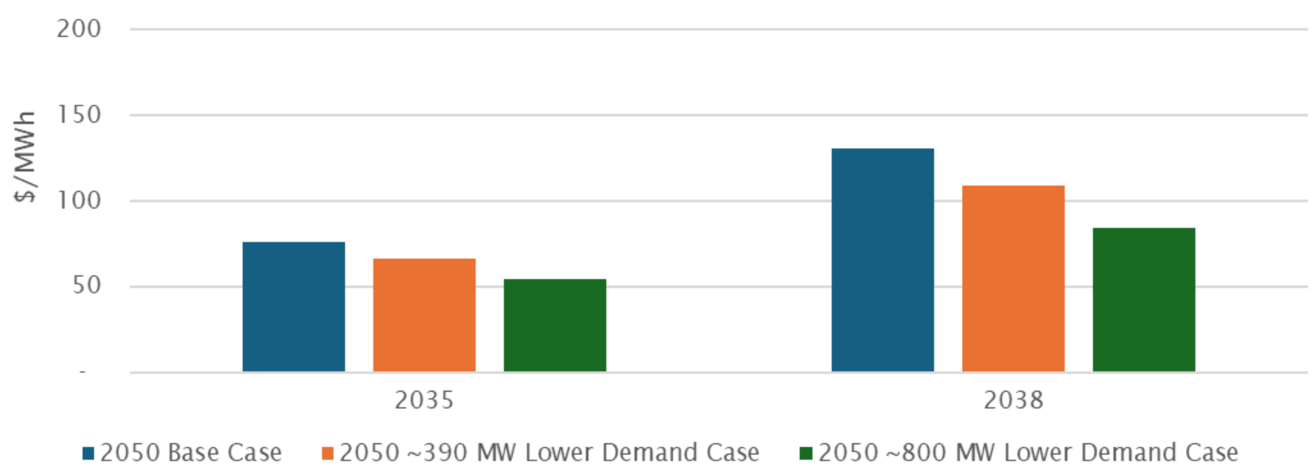
**Annual average Pool Price forecast, 2035 Base Case vs 2035 Lower Demand Cases (weather normal), nominal $/MWh**



# The 2050 Base Case is slightly less sensitive than the 2035 Base Case to demand shocks in 2035, but slightly more sensitive in 2038

- **Under LEI's 2050 ~390 MW Lower Demand Case, the average Pool Price in 2035 is forecasted to be 13% lower than the 2050 Base Case**
  - The percentage change in Pool Price is smaller than the change under the 2035 ~390 MW Lower Demand Case (18%), indicating that supply-demand conditions are less tight under the 2050 Base Case in 2035
- **Under the 2050 ~390 MW Lower Demand Case, the average Pool Price falls by 16% in 2038**
  - The percentage change in Pool Price is slightly larger than the change under the 2035 ~390 MW Lower Demand Case (15%), indicating that supply-demand conditions are tighter under the 2050 Base Case in 2038
- **In the 2050 ~800 MW Lower Demand Case, prices are 29% lower (in 2035) and 36% lower (in 2038)**

**Annual average Pool Price forecast, 2050 Base Case vs 2050 Low Demand Case (weather normal), nominal $/MWh**



# Glossary of key terms

**Ancillary services:** Ancillary services include Operating Reserves, Transmission Must-Run, Black Start, Load Shed Services for imports, and Fast Frequency Response. Ancillary services are procured by the AESO to support the reliable operation of the electric grid on a day-ahead basis.

**Equivalent Forced Outage Rate on demand ("EFORd"):** EFORd measures the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

**Pool Price:** The Alberta wholesale market for electricity is a single-price, competitive energy market, in which market outcomes (e.g., price and dispatch of power plants) are determined by the intersection of demand and supply, subject to certain limitations, such as the price floor at $0/MWh and $1,000/MWh price cap. Generators offer to produce energy at a certain price. AESO, as the system operator, determines the most economic (least cost) dispatch of generators, based on their offers. This happens on a minute-by-minute basis, as demand and supply are constantly changing. The hourly average of the minute-by-minute prices is known as the hourly Pool Price. Generators that are producing electricity within a specific hourly interval get paid the Pool Price and buyers of electricity must pay the Pool Price.

**Scheduled Outage Factor ("SOF"):** SOF measures a generation unit's unavailability due to planned or maintenance outages.

**Short-run marginal costs ("SRMCs"):** SRMCs consist of costs associated with an incremental unit of energy supplied. The largest component of the SRMC for fossil fuel-fired power plants is typically fuel costs (e.g., coal or natural gas prices multiplied by the thermal efficiency of the generating unit in question). The SRMC also contains other non-fuel variable O&M expenses, such as consumables used by the facility's operations to generate the energy, as well as costs associated with carbon emissions.

**Simulation modeling:** Generally, a simulation model is intended to mimic real world dynamics. With respect to the electricity market, simulation modeling determines the dispatch of generating resources in the market (assuming that the lowest cost generator is "dispatched" first in each hour) to meet projected hourly load, subject to technical assumptions regarding generation operating capacity and availability of transmission. This analysis will also produce a forecast of Pool Prices.

**Weather normal:** LEI used actual weather data in its long term energy market modeling, in order to ensure realistic conditions. LEI chose to use 2021 weather conditions (which impacted hourly renewable generation and hourly variation in load) to represent "normal" weather, because 2021 conditions were closest to longer term averages and were neither mild nor abnormally extreme in terms of weather factors that could skew the results towards low likelihood events.

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# Disclaimer notice

**While LEI has taken all reasonable care to ensure that its analysis is complete, power markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Investors, lenders, and others should note that:**

- No results provided or opinions given in LEI's analysis should be taken as a promise or guarantee as to the occurrence of any future events.
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# Module B Study – Annex 2
# Projection of Residential Electric Bills

*prepared for*

Proceeding 28542: AUC Inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta

February 7, 2024

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# Agenda

| | |
|---|---|
| 1 | **Modeling approach** |
| 2 | Key assumptions and inputs |
| 3 | Key modeling results |

# LEI conducted forward-looking simulations of the Alberta power market using a scenario-based approach, in order to estimate future supply adequacy and a typical residential customer's electric bill

### Wholesale electricity market outlook

LEI used its simulation-based modeling suite to forecast market outcomes under **Alberta's current energy-only market framework** – leveraging information from AESO's preliminary 2024 Long-term Outlook ("LTO")

### Scenario analysis

LEI considered key exogenous drivers – like carbon policy, pace of renewable development, and level of demand – in the simulation modeling through scenario analysis and sensitivities

### Impact analysis

#### Probabilistic assessment of reliability

To assess supply adequacy*, LEI simulated weather-based variability and different plausible generation outage patterns on top of the scenario outcomes to develop a distribution of potential market outcomes

#### Total electric bill impacts

LEI paired the supply forecast emerging from the scenario analysis with transmission and distribution cost projections to assess affordability impacts for residential customers

***Focus of this Annex***

** LEI's terms of reference focus on supply adequacy, notwithstanding other dimensions of system reliability.*

# A typical residential customer bill for electricity in Alberta is comprised of four components: supply, transmission, distribution, and other charges

**In 2023, the monthly electric bill for a typical residential customer that consumed 589 kWh/month ranged from \$194 to \$278, depending on the distribution facility owner ("DFO")**

| Energy supply costs | | Transmission costs | | Distribution costs | | Other charges |
|---|---|---|---|---|---|---|
| \$115-\$120<br>On average, 54% of total bill | + | \$23-\$28<br>On average, 12% of total bill | + | \$28-\$92<br>On average, 21% of total bill | + | \$22-\$38<br>On average, 14% of total bill |

Notes:

- Energy component is based on average Regulated Rate Option ("RRO") prices for January through December 2023 for each DFO.
- Other charges component includes retailer fixed charges, Local Access Fees ("LAF"), and Goods and Services Tax ("GST"). LAF for EPCOR and ENMAX is based on Edmonton (\$0.0105/kWh in 2023) and Calgary (11.11%), respectively. LAF for ATCO (4.28%) and Fortis (15.20%) is based on average LAF for top five municipalities (by population) for each service territory.
- Other charges component excludes riders (e.g., Balancing Pool Adjustment, Transmission Access Charge Adjustment Rider), as riders were also excluded from LEI's forward-looking bill impact analysis. Riders were excluded from the forward-looking analysis as it is unclear how they will evolve over time. In 2023, total riders ranged from approximately \$2 to \$17 per month, depending on the DFO.

# LEI's affordability assessment leveraged other existing analysis and information on costs, where appropriate


- **AESO's 2020 Delivered Cost of Electricity Report**
  - ✓ Provides an approach for building monthly electricity bill estimates for an average residential customer
- **AESO's 2022 Transmission Rate Projection**
  - ✓ Provides an approach for estimating average transmission rates going forward
- **AESO's 2022 Long-term Transmission Plan ("LTP") and 2023 Grid Reliability Update**
  - ✓ Provides an outlook for major transmission investments needed under Base Cases
- **AESO's 2022 Net-Zero Emissions Pathways Report**
  - ✓ Renewables and Storage Rush Scenario provides an outlook for additional transmission investments needed to support higher levels of renewables
- **Guidehouse's 2024 Net-Zero Analysis of Alberta's Electricity Distribution System (prepared for the AUC)**
  - ✓ Provides an outlook for distribution system costs for integrating increasing levels of solar DERs and EVs

# The electric bill impact analysis relies on AESO's forecasts and information, results from LEI's weather normal scenario analysis, as well as current regulatory policy

▶ **LEI estimated the impact of future supply changes and transmission and distribution cost trajectories on the typical residential customer's electric bill at the DFO level by component**

**To derive monthly electric bill estimates for 2024-2040:**

**Energy supply costs**

- Based on the load-weighted average Pool Prices from LEI's POOLMod outputs, which differ by scenario

\+

**Transmission costs**

- Includes AESO's 2022 LTP major projects, plus more recent announcements from AESO's 2023 Grid Reliability Update
- Incorporates additional transmission costs for the More Renewables Cases

\+

**Distribution costs**

- Includes service charges
- 2023 rates escalated by I-X + Growth
- Incorporates distribution cost impacts of integrating solar DERs and EVs (based on Guidehouse analysis commissioned by the AUC)

\+

**Other charges**

- Local access fee ("LAF") escalated based on average observed change historically
- Includes GST
- Excludes riders (e.g., Balancing Pool Adjustment, Transmission Access Charge Adjustment Rider)

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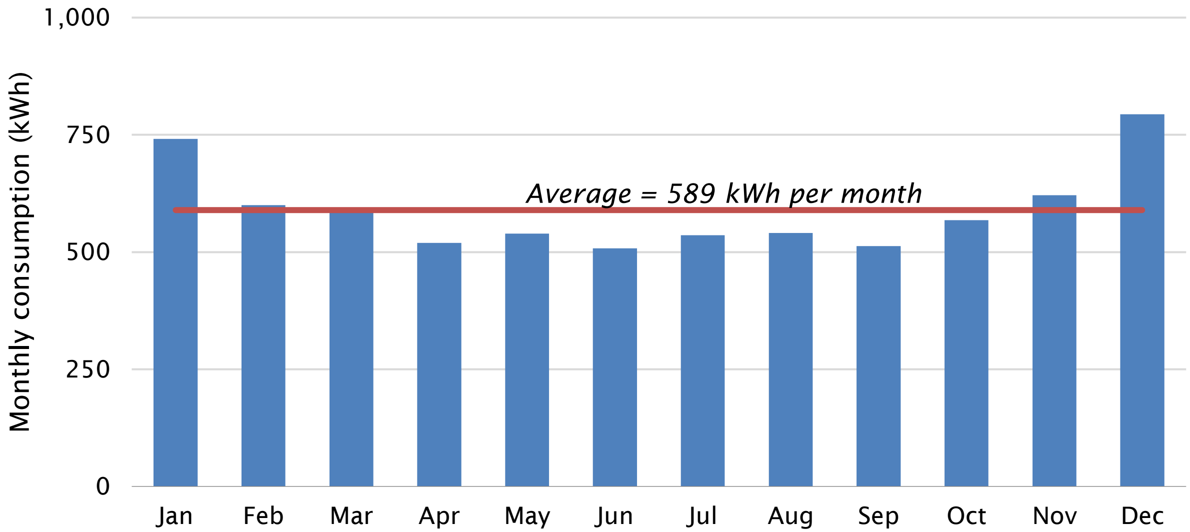
# The hourly load profile for a typical residential customer is consistent with that used in AESO's Delivered Cost of Electricity analysis

- **Electricity consumption for a typical residential customer averages 589 kWh per month; this assumption is maintained throughout the forecast period**

**Monthly residential consumption profile (kWh)**

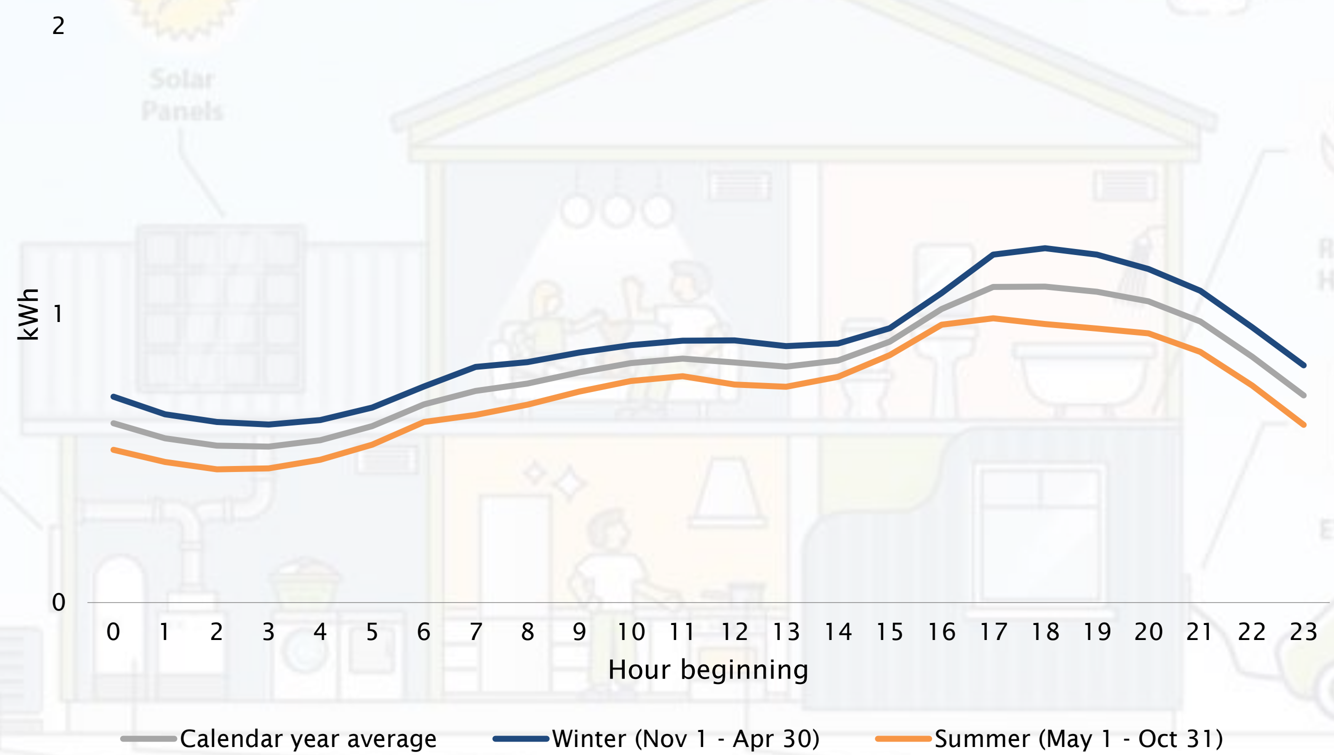



- **To test whether this assumption should change over time, LEI compared the growth in annual AIL energy (GWh) from AESO's preliminary 2024 LTO to provincial population growth estimates from the Government of Alberta**
  - Annual AIL energy grows at a CAGR of 1.1% over the 2024-2040 period according to the AESO, while the Government of Alberta forecasts population growth at a CAGR of 1.6% over the same timeframe
  - However, the ratio of AIL energy to population is fairly stable over time, which does not suggest a material change in electricity consumption per capita

Sources: AESO. *Delivered Cost of Electricity Report.* May 2020; AESO. *2024 LTO Preliminary Data File.* November 15, 2023; Government of Alberta. *Alberta Population Projections, 2023-2051 – Alberta and Census Divisions – Data Tables.* Updated July 5, 2023.

# A typical household in Alberta consumes more electricity in the evening than in the middle of the day

## Average residential daily load profile by season (kWh)

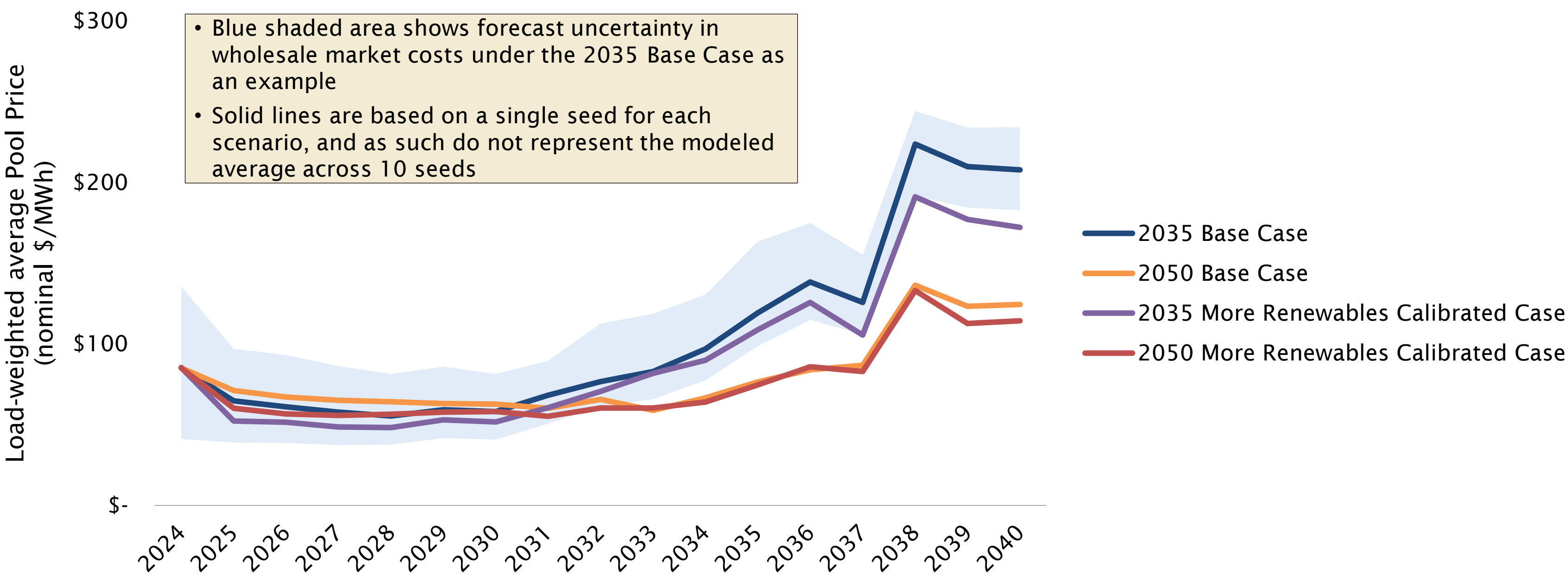



Note: Winter and summer months align with the AESO's seasonal definitions (*see for example* AESO. [2022 Annual Market Statistics.](#) March 2023).

# Energy charges for a typical residential customer are based on the load-weighted average of LEI's hourly Pool Price forecast for each scenario (from the weather normal scenario analysis)

- **Energy charges increase the most under the 2035 Base Case (CAGR of 5.7% from 2024 to 2040), followed by the 2035 More Renewables Calibrated Case (CAGR of 4.5%), the 2050 Base Case (CAGR of 2.4%), and the 2050 More Renewables Calibrated Case (CAGR of 1.9%)**
- **Pool Prices, even under weather normal conditions, may vary due to timing of generation outages – this variability (uncertainty) was assessed in the energy charge calculations**
  - For example, under the 2035 Base Case, load-weighted average Pool Prices range +/- $50/MWh around the average at most (see blue shaded area around the blue line), which equates to approximately +/- $30 on a monthly electric bill (assuming electricity consumption of 589 kWh per month)

**Load-weighted average Pool Price by scenario (nominal $/MWh)**



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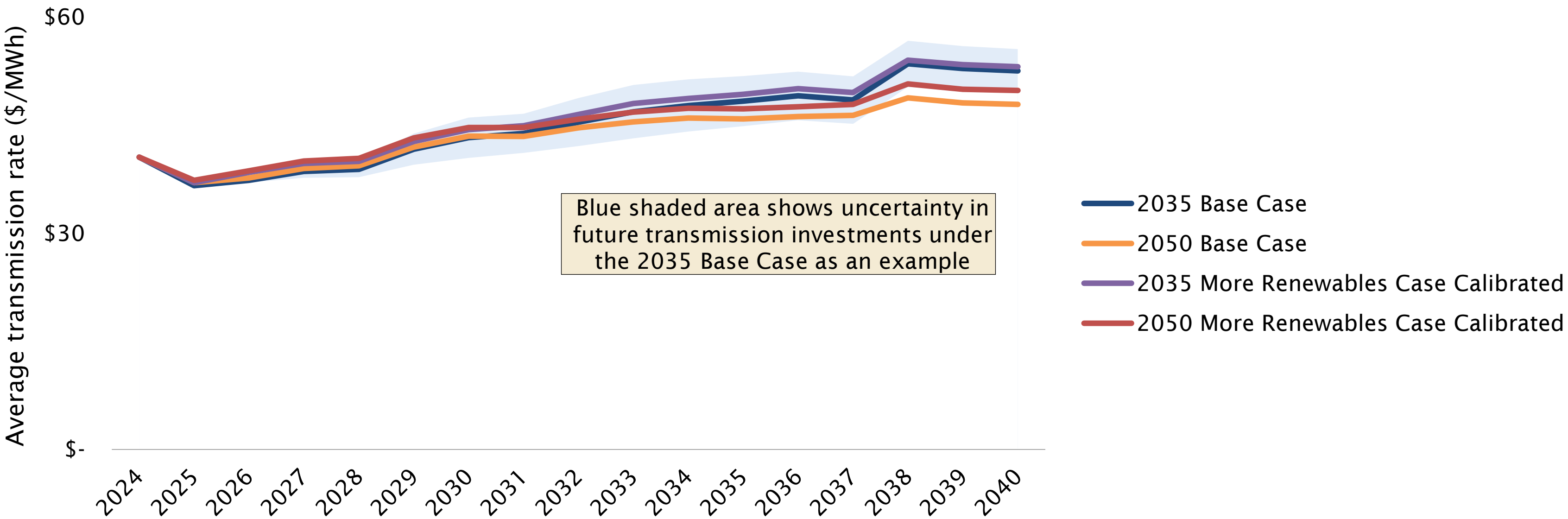
# Transmission rates for each scenario are based on different potential transmission investment paths, given varying amounts of renewables and linkage between Pool Prices and ancillary services costs

- **Transmission rates increase the most under the 2035 More Renewables Calibrated Case (CAGR of 1.7% from 2024 to 2040), followed by the 2035 Base Case (CAGR of 1.6%), the 2050 More Renewables Calibrated Case (CAGR of 1.3%), and the 2050 Base Case (CAGR of 1.0%); overall, transmission rates grow more slowly than energy charges**
- **Transmission rates are subject to investment uncertainty; LEI tested the impact on transmission rates of increasing or decreasing major project cost estimates by 50%**
  - For example, under the 2035 Base Case, testing +/- 50% around project cost assumptions introduces at most +/- $4/MWh to average transmission rates (see blue shaded area around the blue line), which equates to approximately +/- $2 on a monthly electric bill (assuming consumption of 589 kWh per month)*

**Average transmission rate by scenario (nominal $/MWh)**




* Also assuming that the consumption profile of non-residential customers and their contribution to transmission cost recovery does not change.

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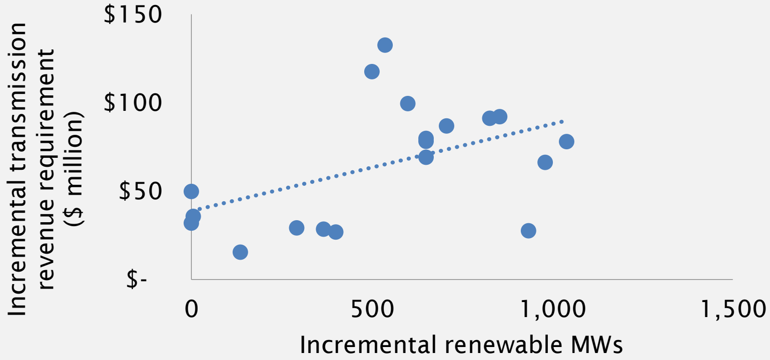
# Transmission rates were estimated by leveraging AESO's Transmission Rate Projection model to incorporate several transmission cost components

## Transmission costs included in the Base Cases

- **Revenue requirement for existing assets**
  - Based on AESO's 2024 ISO Tariff Update Application and the general tariff applications ("GTAs") of the transmission facility owners ("TFOs")
- **Revenue requirement for forecast connection projects and capital maintenance and replacement**
  - Based on TFO GTAs and AESO's 2022 Transmission Rate Projection
- **Revenue requirement for future transmission investment**
  - Based on AESO's 2022 LTP projects, with updates from AESO's 2023 Grid Reliability Update and discussions with AESO staff
- **Operating reserves ("OR") costs, which are keyed off energy market trends and vary by scenario**
  - OR costs are linked to LEI's forecasted Pool Prices under each scenario and load growth

## Additional transmission costs included in the More Renewables Cases

- **Revenue requirement for additional transmission investment needed to support higher levels of renewables**
  - LEI considered the relationship between the transmission revenue requirement and additional renewable MWs assumed under the Renewables and Storage Rush Scenario in AESO's 2022 Net-Zero Emissions Pathways Report:




  - LEI estimates ~$1.9 billion in additional transmission capital costs would be needed over the 2024-2040 period to support the ~4.5 GW of additional renewables added in LEI's More Renewables Cases; this would increase transmission rates by at most $2/MWh under the More Renewables Cases relative to the Base Cases

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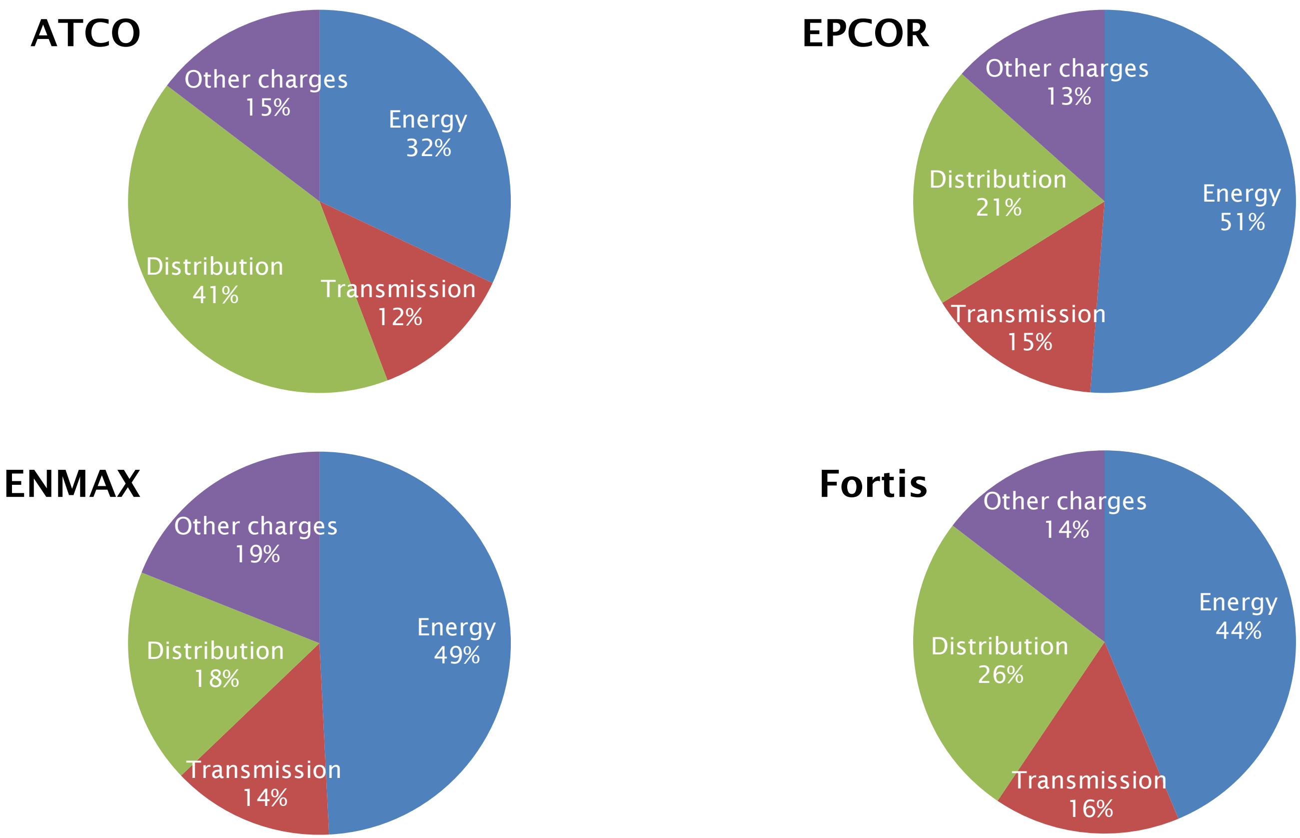
# The distribution component varies by DFO, due to differences in service territories (rural vs urban)

- **The distribution component accounts for a significant portion of total residential electric bills for ATCO (41% on average over the 2019-2023 period), compared to Fortis (26%), EPCOR (20%), and ENMAX (18%)**

**Residential electric bill breakdown by component and DFO (2019-2023 average)**




Note: Excludes riders (e.g., Balancing Pool Adjustment, Transmission Access Charge Adjustment Rider).

# The distribution component is escalated from current levels by I-X + Growth, consistent with the third-generation performance-based regulation ("PBR3") framework

*I-X escalation is the same across all DFOs*

### Inflation (I) factor averages 2.4% per year over the 2024-2040 period

- Under PBR3, the I factor is based on a weighted average of the Alberta Fixed Weighted Index ("FWI") (60%) and the Alberta Consumer Price Index ("CPI") (40%)
- Alberta FWI forecasts are not readily available, so LEI based near-term inflation (2024-2026) on the average Alberta CPI forecasts from the big five banks and Government of Alberta; for 2027 onwards, LEI assumed 2% inflation, consistent with AESO's long-term inflation assumption
- LEI estimated and included a 30 bp adder in each year, to account for the historical observed impact of incorporating FWI data in the I factor formula

–

### Productivity (X) factor is set at 0.4% per year

- Under PBR3 (AUC Decision 27388-D01-2023 issued in October 2023), the X factor of 0.4% is based on 0.1% industry total factor productivity ("TFP") growth and a stretch factor, plus a 0.3% benefit-sharing mechanism

+

### Customer growth escalator

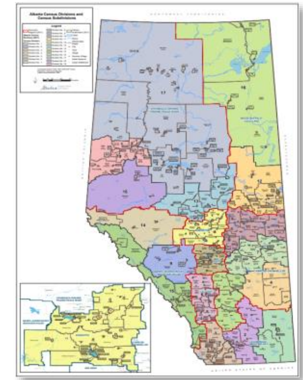
- Differs by DFO
- See next slide for more details

▶ **The distribution component in LEI's forward-looking analysis also incorporates the impact of increasing levels of DER and EV penetration on distribution system costs**

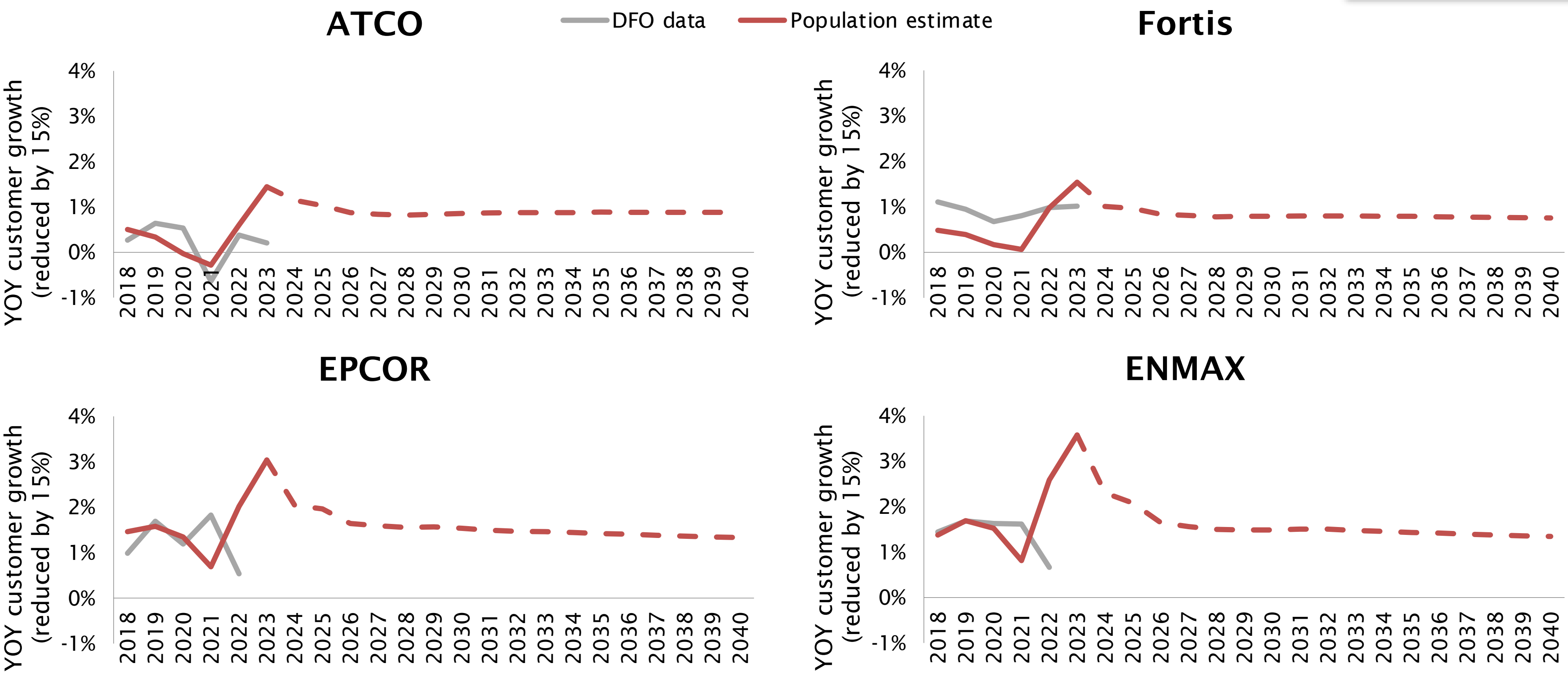
- LEI leveraged Guidehouse's 2024 Net-Zero Analysis of Alberta's Electricity Distribution System Report, which estimates integration costs associated with varying levels of solar DERs and EVs; LEI rescaled the Guidehouse estimates to align with the level of DERs and EVs forecasted in AESO's preliminary 2024 LTO

Sources: AUC. *Decision 27388-D01-2023, 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities.* October 4, 2023; Guidehouse. *Net-Zero Analysis of Alberta's Electricity Distribution System.* January 22, 2024.

# Under PBR3, a customer growth escalator is applied to determine each DFO’s K-bar capital funding, and is calculated as the annual change in the average customer count, reduced by 15%



- **Given customer growth forecasts by DFO are not readily available, LEI based the escalator on Government of Alberta population forecasts at the census division level, reduced by 15% (consistent with PBR3)**
  - LEI aggregated the population estimates for the census divisions that most closely overlap each DFO’s service territory
- **Over the 2024-2040 period, LEI’s customer growth escalator averages 0.9% for ATCO, 0.8% for Fortis, 1.5% for EPCOR, and 1.5% for ENMAX**




Source: Government of Alberta. *Alberta Population Projections, 2023-2051 – Alberta and Census Divisions – Data Tables.* Updated July 5, 2023.

# Agenda

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# Residential electric bills are expected to be highest under the 2035 Base Case and lowest under the 2050 More Renewables Calibrated Case

- Across all scenarios, residential electric bills are expected to grow at a rate faster than inflation (2% per year) in the later years of the forecast period
- Despite higher bills, electric service reliability is expected to deteriorate*

## Projected residential electric bill CAGRs by DFO and scenario

### *2035 Base Case*
*(Federal draft CER)*

| DFO | 2025-2030 CAGR | 2030-2040 CAGR |
|---|---|---|
| ATCO | 2.1% | 5.5% |
| EPCOR | 1.9% | 7.4% |
| ENMAX | 1.6% | 7.7% |
| Fortis | 1.9% | 6.7% |
| **Province avg.** | **1.9%** | **6.8%** |

### *2035 More Renewables Calibrated Case*
*(Federal draft CER with more renewables)*

| DFO | 2025-2030 CAGR | 2030-2040 CAGR |
|---|---|---|
| ATCO | 2.6% | 5.0% |
| EPCOR | 2.7% | 6.7% |
| ENMAX | 2.5% | 7.0% |
| Fortis | 2.7% | 6.1% |
| **Province avg.** | **2.6%** | **6.2%** |

### *2050 Base Case*
*(Provincial plan)*

| DFO | 2025-2030 CAGR | 2030-2040 CAGR |
|---|---|---|
| ATCO | 1.9% | 3.7% |
| EPCOR | 1.6% | 4.6% |
| ENMAX | 1.3% | 4.7% |
| Fortis | 1.7% | 4.1% |
| **Province avg.** | **1.6%** | **4.3%** |

### *2050 More Renewables Calibrated Case*
*(Provincial plan with more renewables)*

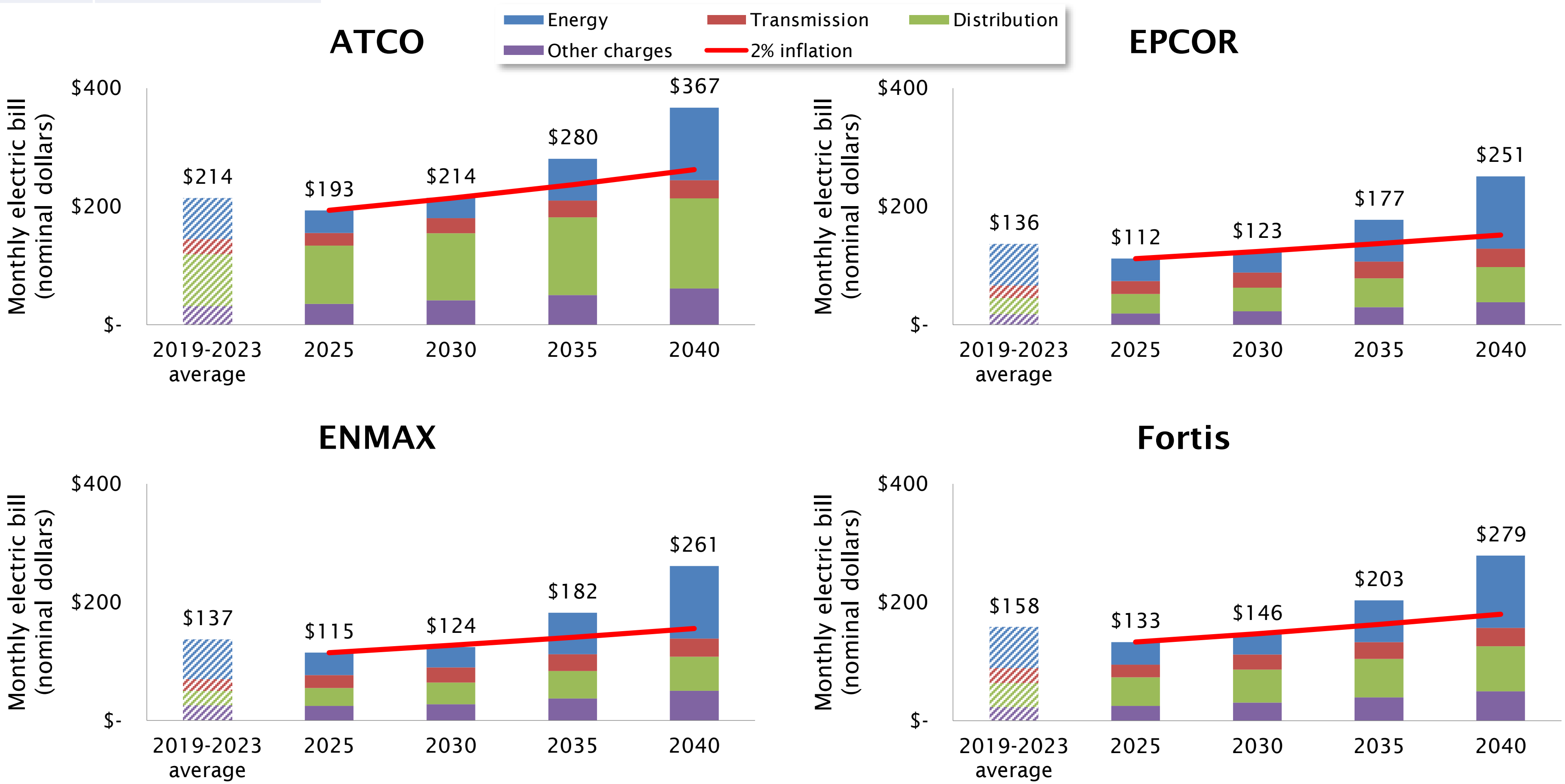
| DFO | 2025-2030 CAGR | 2030-2040 CAGR |
|---|---|---|
| ATCO | 2.4% | 3.6% |
| EPCOR | 2.4% | 4.5% |
| ENMAX | 2.2% | 4.5% |
| Fortis | 2.4% | 4.1% |
| **Province avg.** | **2.4%** | **4.2%** |

* LEI's electric bill impact analysis is paired with the reliability outcomes from LEI's long term weather-normal scenario analysis – see Annex 1 *(Scenario Analysis: Long Term Weather-Normal Energy Market Forecast)* for more details.

# Typical residential bills are the highest under the 2035 Base Case, and are estimated to increase by a province-wide average CAGR of 4.2% from 2024 to 2040 – over twice the assumed rate of inflation (2% per year, see red lines)

| DFO | 2035 Base Case CAGR (2024-2040) |
|---|---|
| ATCO | 3.7% |
| EPCOR | 4.4% |
| ENMAX | 4.5% |
| Fortis | 4.1% |

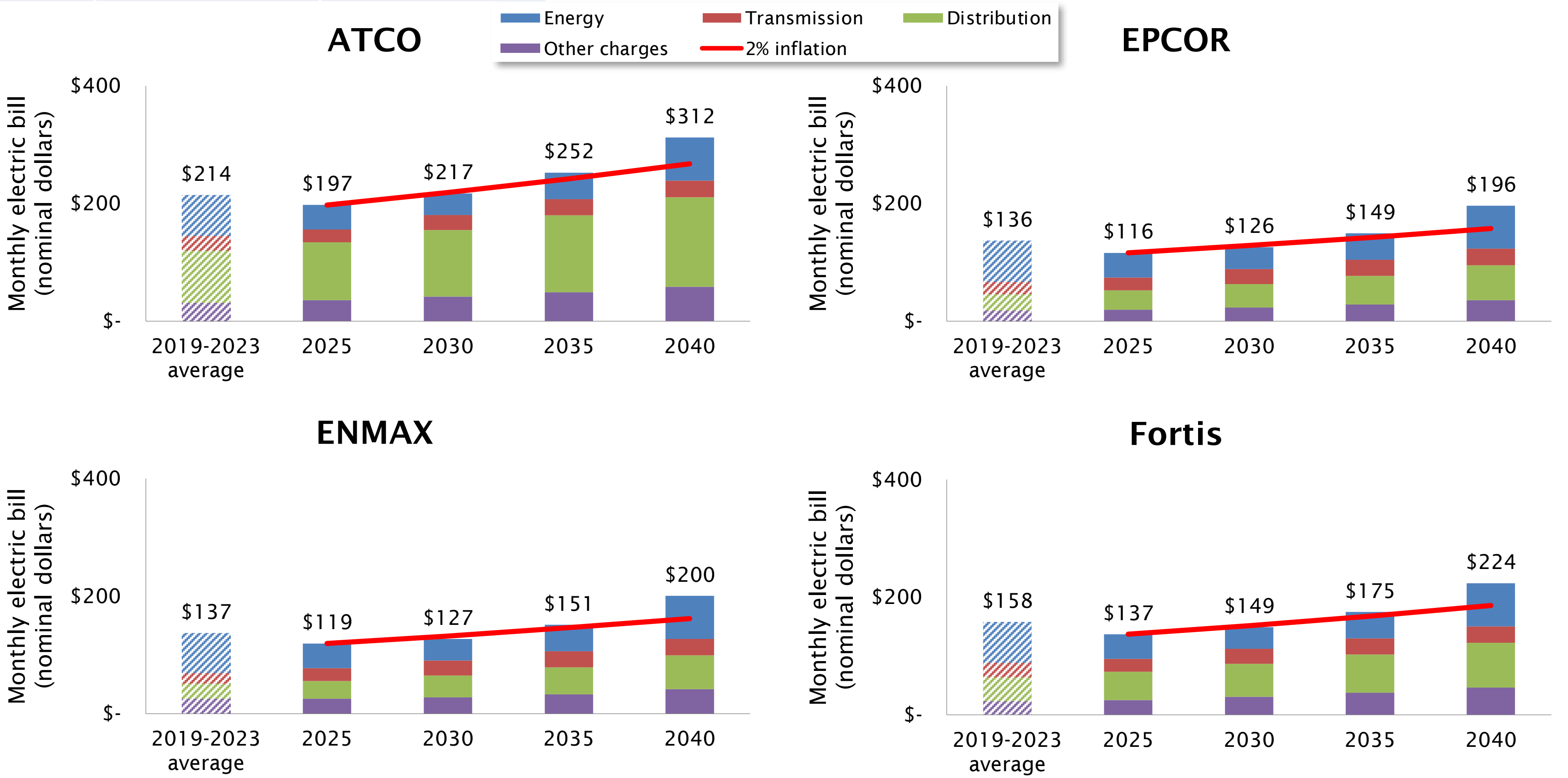
***2035 Base Case***



# Under the 2050 Base Case, typical residential electric bills are estimated to increase at a slower province-wide average CAGR of 2.8% from 2024 to 2040, due to lower Pool Prices relative to the 2035 Base Case

| DFO | 2035 Base Case CAGR (2024-2040) | 2050 Base Case CAGR (2024-2040) |
|---|---|---|
| ATCO | 3.7% | 2.7% |
| EPCOR | 4.4% | 2.9% |
| ENMAX | 4.5% | 2.8% |
| Fortis | 4.1% | 2.7% |

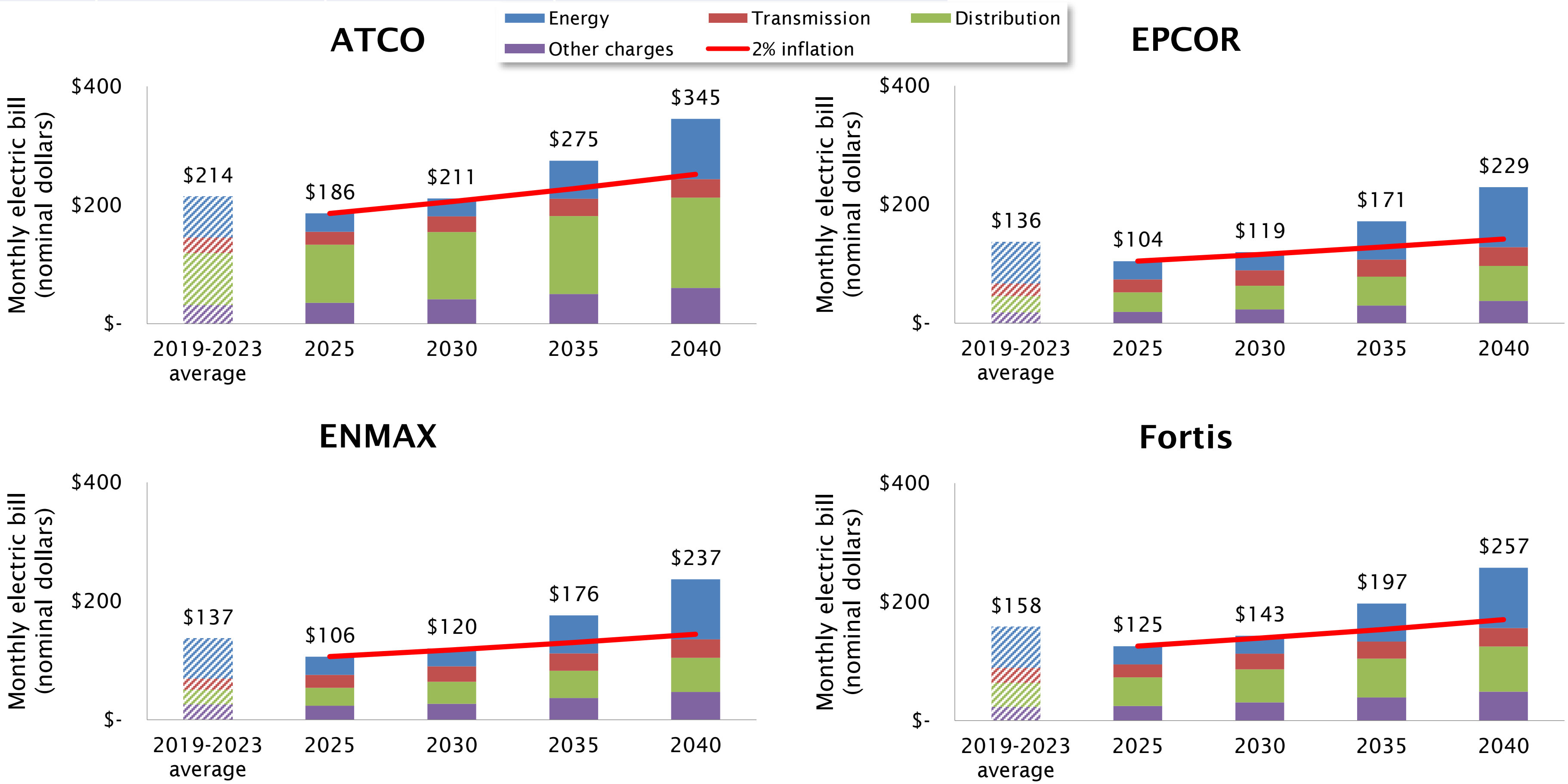
## 2050 Base Case



# Typical residential bills under 2035 More Renewables Calibrated Case grow slower than 2035 Base Case (province-wide average CAGR of 3.7% vs 4.2%); impact of lower Pool Prices somewhat muted by higher transmission rates

| DFO | 2035 Base Case CAGR (2024-2040) | 2050 Base Case CAGR (2024-2040) | 2035 More Renewables Calibrated Case CAGR (2024-2040) |
|---|---|---|---|
| ATCO | 3.7% | 2.7% | 3.3% |
| EPCOR | 4.4% | 2.9% | 3.9% |
| ENMAX | 4.5% | 2.8% | 3.8% |
| Fortis | 4.1% | 2.7% | 3.6% |

***2035 More Renewables Calibrated Case***



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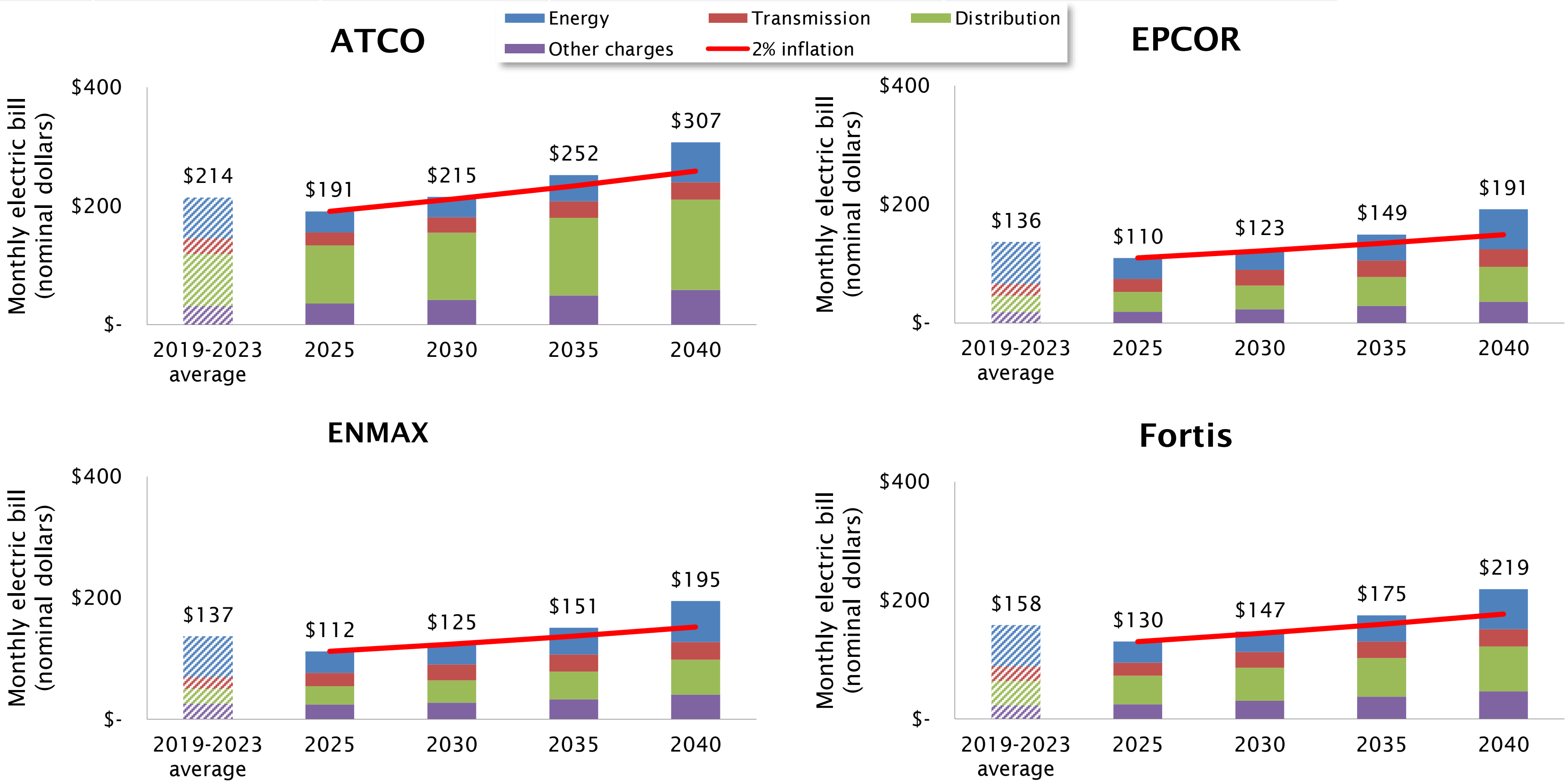
# Typical residential bills are the lowest under the 2050 More Renewables Calibrated Case, increasing by a province-wide average CAGR of 2.6% for 2024 to 2040 – but still above the assumed long-term inflation rate (2%)

| DFO | 2035 Base Case CAGR (2024-2040) | 2050 Base Case CAGR (2024-2040) | 2035 More Renewables Calibrated Case CAGR (2024-2040) | 2050 More Renewables Calibrated Case CAGR (2024-2040) |
|---|---|---|---|---|
| ATCO | 3.7% | 2.7% | 3.3% | 2.6% |
| EPCOR | 4.4% | 2.9% | 3.9% | 2.7% |
| ENMAX | 4.5% | 2.8% | 3.8% | 2.6% |
| Fortis | 4.1% | 2.7% | 3.6% | 2.6% |

***2050 More Renewables Calibrated Case***



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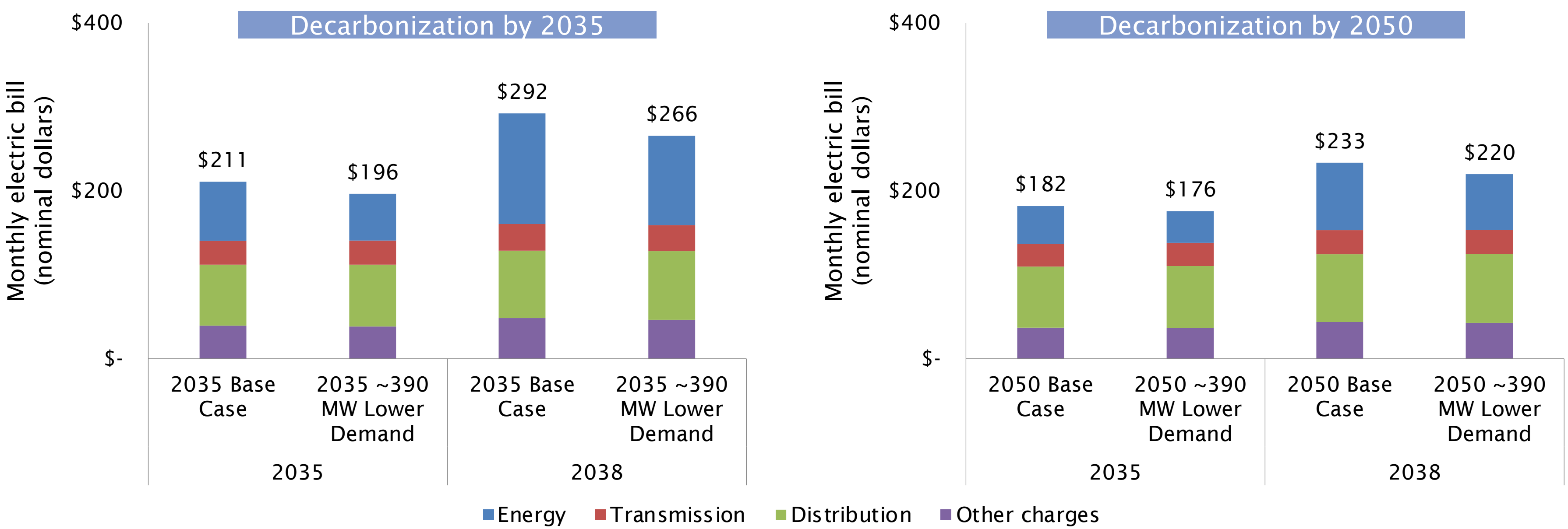
# On a province-wide average basis, residential electric bills are between 3% to 9% lower under the ~390 MW Lower Demand Cases relative to the Base Cases

- **The percentage reduction in residential electric bills is greater under the 2035 ~390 MW Lower Demand Case than the 2050 ~390 MW Lower Demand Case, consistent with Pool Price results**
- **The transmission component does not change significantly with lower demand – although the transmission revenue requirement is recovered from a lower DTS load (increasing transmission costs), operating reserves costs decrease (decreasing transmission costs)**
- **Also, the distribution component increases by 1% on average with lower demand due to increases in the "Distribution – Energy Charge", which is recovered on a $/kWh basis**

**Province-wide average monthly electric bill, Base Cases vs ~390 MW Lower Demand Cases, nominal dollars**



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# Typical residential electric bills are expected to closely track outcomes in the wholesale energy market, and thus are rising above the rate of inflation in all scenarios; despite higher bills, electric service reliability worsens

## Typical residential electric bills are expected to be lower under a decarbonization policy that pursues net zero by 2050 rather than by 2035

- Residential electric bills rise at a slower rate under the 2050 Base Case (province-wide average CAGR of 2.8% from 2024 to 2040) than under the 2035 Base Case (4.2%)
- Electric bill estimates are subject to forecast uncertainty – for example, under the 2035 Base Case, Pool Prices represent +/- $50/MWh at most (which is approximately +/- $30 per month), based on the impact of generation outages; transmission costs represent a further +/- $4/MWh at most (which is approximately +/- $2 per month), based on investment uncertainty

## With additional renewables, electric bills are expected to be lower than under the Base Cases – although the impact of lower Pool Prices is somewhat offset by higher transmission rates

- Electric bills rise at a province-wide average CAGR of 3.7% from 2024 to 2040 under the 2035 More Renewables Calibrated Case, and 2.6% under the 2050 More Renewables Calibrated Case

## Lower demand in the form of an unexpected "demand shock" tends to reduce the typical residential electric bill

- LEI observed that the reduction in Pool Prices far outweighs the loss of billing determinants in the ~390 MW Lower Demand Cases tested – this is a favourable feature of the energy-only market

## However, all scenarios project residential electric bills outpacing inflation in the later years of the forecast period, despite deteriorating reliability

- LEI's electric bill impact analysis is paired with the reliability outcomes discussed in Annex 1 *(Scenario Analysis: Long Term Weather-Normal Energy Market Forecast)*, which anticipates lower levels of electric service reliability than Albertans have become accustomed to

## LEI's analysis reports total residential electric bill estimates for an "average" month (assuming 589 kWh of consumption), and so does not capture the monthly volatility that could arise

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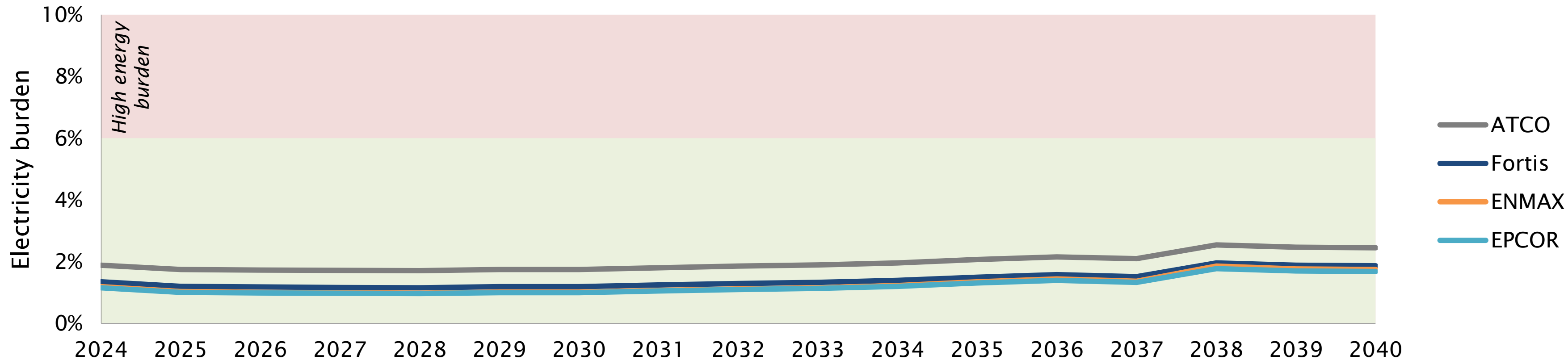
# LEI also conducted a "share of wallet" analysis to provide an indication of affordability: electric bills for a typical residential customer remain within industry-accepted affordability thresholds, although reliability worsens

- **The "share of wallet" is measured as the percentage of gross household income spent on energy bills (electricity and gas) – high energy burden > 6%; severe energy burden > 10%**
- **LEI assessed the electricity burden over time under each scenario, based on escalating Alberta average total income (2021) – $115,600 per year – using growth in Alberta CPI**

**Electricity burden (%), 2035 Base Case**




**Average electricity burden (%) by DFO under various scenarios (2024-2040)**

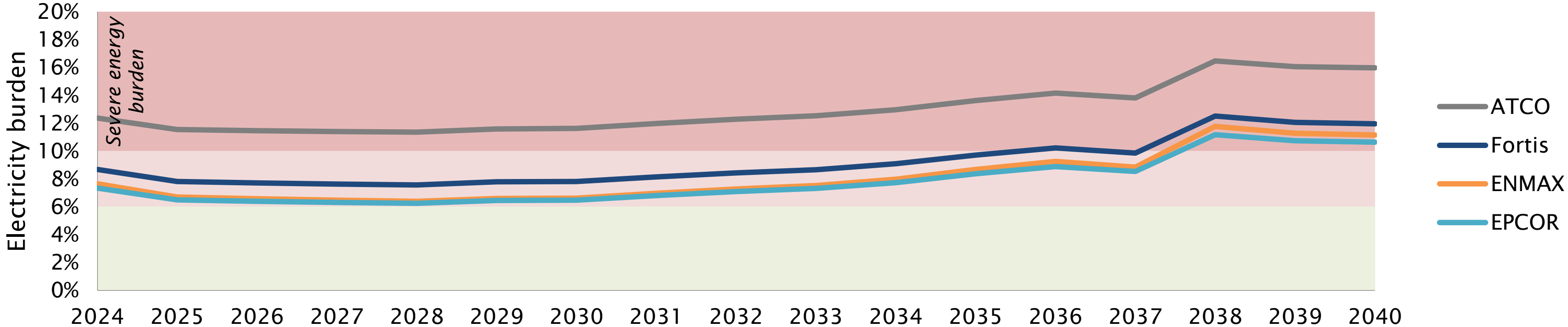
| DFO | 2035 Base Case | 2050 Base Case | 2035 More Renewables Calibrated Case | 2050 More Renewables Calibrated Case |
|---|---|---|---|---|
| ATCO | 2.0% | 1.9% | 1.9% | 1.8% |
| EPCOR | 1.2% | 1.1% | 1.2% | 1.1% |
| ENMAX | 1.3% | 1.1% | 1.2% | 1.1% |
| Fortis | 1.4% | 1.3% | 1.4% | 1.3% |
| **Province-wide avg.** | **1.5%** | **1.3%** | **1.4%** | **1.3%** |

*See for example* Fisher, Sheehan & Colton. [Home Energy Affordability Gap](); Alberta average total income from Statistics Canada Table 11-10-0190-01.

# For the lowest income customers in the province, the share of wallet analysis shows a much higher energy burden, breaching 10% (severe energy burden) for ATCO throughout the forecast period and for other DFOs in later years*

- **LEI assessed the electricity burden in Alberta over time under the various scenarios for the lowest income customers**
  - Income based on Alberta average total income for the lowest income decile (2021) – $15,100 per year – escalated using growth in Alberta CPI
  - Electricity consumption based on Alberta average household electricity consumption for households with income under $20,000 per year (2019 – latest available data) – 458 kWh per month

## Electricity burden (%), 2035 Base Case




## Average electricity burden (%) by DFO under various scenarios (2024-2040)

| DFO | 2035 Base Case | 2050 Base Case | 2035 More Renewables Calibrated Case | 2050 More Renewables Calibrated Case |
|---|---|---|---|---|
| ATCO | 13.0% | 12.3% | 12.7% | 12.2% |
| EPCOR | 7.8% | 7.1% | 7.5% | 7.0% |
| ENMAX | 8.1% | 7.3% | 7.7% | 7.2% |
| Fortis | 9.2% | 8.5% | 8.8% | 8.3% |
| **Province-wide avg.** | **9.5%** | **8.8%** | **9.2%** | **8.7%** |

* Under the 2035 Base Case and the 2035 More Renewables Calibrated Case only.

Sources: Statistics Canada Tables 11-10-0192-01 and 25-10-0062-01, 1 GJ = 277.7778 kWh (*see* Canada Energy Regulator. *Energy conversion tables*)

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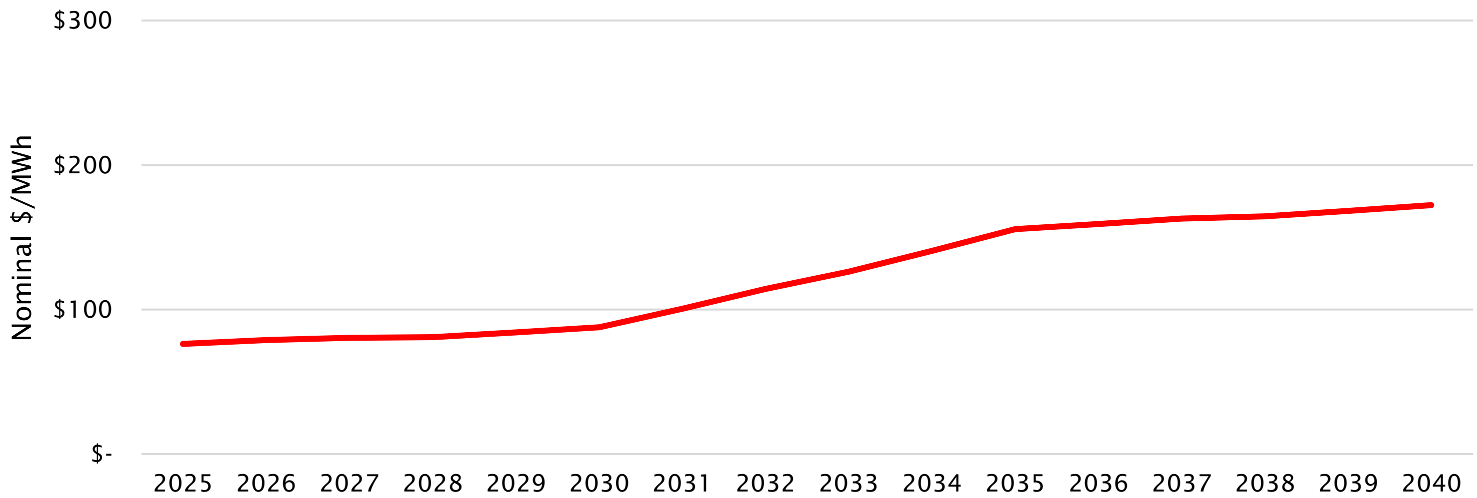
# To assess the potential impact on industrial customers, LEI compared around-the-clock Pool Prices plus levelized transmission costs to the levelized costs of building an off-grid solution

- **To assess the levelized costs of an off-grid solution for an industrial customer, LEI assumed that the primary behind-the-fence generator would be a CCGT, with a backup peaker**
  - LEI's assumed capital costs and fixed O&M costs are for one CCGT unit plus one peaker unit – capital cost and fixed O&M cost assumptions are from AESO's preliminary 2024 LTO
  - Operating assumptions (heat rate, fuel costs, nominal variable O&M, and carbon costs) are for one CCGT unit
  - Capacity factor is set at 90%
  - Pre-tax weighted average cost of capital ("WACC") is set at 10.5%, consistent with AESO's assumptions for merchant generation, recognizing that individual industrial customers' WACC may be different

**Levelized cost of a hypothetical off-grid solution (nominal $/MWh)**

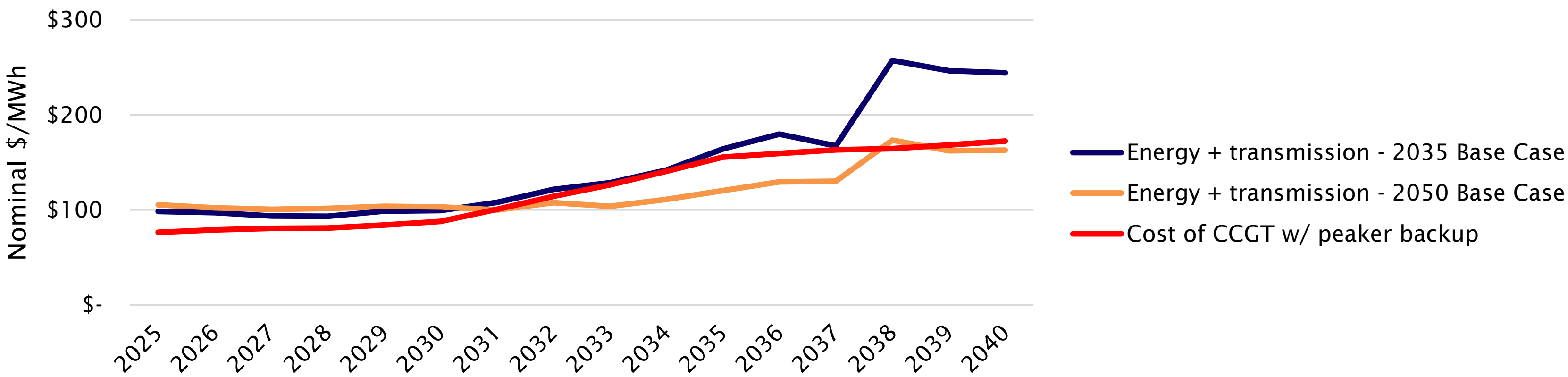



Note: Levelized cost increases over time due to gas prices and carbon costs.

# LEI's illustrative analysis suggests that an off-grid solution may be more economic than acquiring electricity from the grid for some period of time

- **LEI assumed the large industrial customer would only have to pay for energy and transmission (and would be consuming these services around the clock)**
  - Under the 2035 Base Case, the levelized cost of an off-grid solution is lower than paying for energy and transmission costs; as energy costs rise sharply, the incentive for economic bypass increases
  - Under the 2050 Base Case, the levelized cost of an off-grid solution is no longer lower than grid service beyond 2031
  - However, given worsening reliability under both Base Cases, remaining on grid may not support the level of electric service reliability that Albertan customers have become accustomed to, increasing the incentive for economic bypass

**Grid-connected power and transmission costs faced by an industrial customer under Base Cases vs cost of an off-grid solution (nominal $/MWh)**




- **This is an illustrative analysis**
  - LEI did not consider any capital budget constraints of an industrial customer, which would mean a different IRR and cost of capital and therefore raise/lower the levelized cost of the off-grid solution
  - LEI assessed only one potential off-grid solution; other technology solutions exist (e.g., renewables + BESS)
  - Some customers may want additional redundancy; the costs of such redundancy have not been included
  - Furthermore, there may be other potential financial benefits of an off-grid solution that have not been accounted for in our illustrative analysis (e.g., hot water and steam service from a BTF generator)

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**While LEI has taken all reasonable care to ensure that its analysis is complete, power markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Investors, lenders, and others should note that:**

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London Economics International LLC

# Module B Study – Annex 3
# Probabilistic Supply Adequacy Analysis

*prepared for*

Proceeding 28542: AUC Inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta

February 7, 2024

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# Agenda

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# LEI's probabilistic supply adequacy analysis builds upon the foundation of the POOLMod and ConjectureMod modeling results

**Simulation-based dispatch model that projects a single market-clearing price for each hour**

## POOLMod

- LEI's proprietary simulation dispatch model
- Consists of several key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch

**Above SRMC offer behaviour provides an investment signal under the energy-only market**

## ConjectureMod

- Game theory module within POOLMod for the Alberta market
- Projects above short-run marginal cost ("SRMC") offers, replicating real-world outcomes; offers will be dynamic and change daily with evolving market conditions

**Probabilistic assessment of weather-related factors**

## WeatherMod

- Assesses reliability and resource adequacy and tests the resiliency of the system to plant outages and varying weather conditions
- Allows for stochastic variation of generation outages, and consideration of weather patterns and their impact on load, intermittent renewable generation, as well as unplanned outages

*Focus of this Annex*

# The probabilistic supply adequacy analysis is conducted using the same tools as LEI's long term weather-normal modeling, but incorporates far more weather combinations

## Inputs

### Long term weather-normal modeling

- Hourly load pattern based on 2021 data
- Wind and solar hourly capacity factors based on 2021 data
- 10 "seeds" for random maintenance and outages

### Probabilistic supply adequacy analysis

- Hourly load pattern, and wind and solar capacity factors from 5 historical years (2018-2022)
- 25 synthetic hourly weather patterns
- 50 "seeds" for random maintenance and outages

### Common inputs

- Fuel prices
- Carbon prices
- Emissions policy
- Load growth
- Expected retirements
- New entry

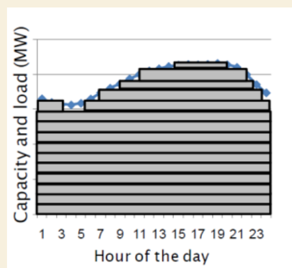
## LEI's propriety energy market simulation model, POOLMod

### Stage 1: Commitment

Is plant available?

No → Not committed for dispatch

Yes → Review technical capabilities of units




Schedule hydro based on optimal duration of operation

Competitive bidding

### Stage 2: Dispatch

Incremental offers are sorted from lowest to highest

Resources dispatched based on offer price

Market clearing price set equal to the bid of the most expensive dispatched resource

## Outputs

### Long term weather-normal modeling

- 20-year price forecast based on "weather-normal" scenario
- Focuses on average Pool Price and profitability of assets

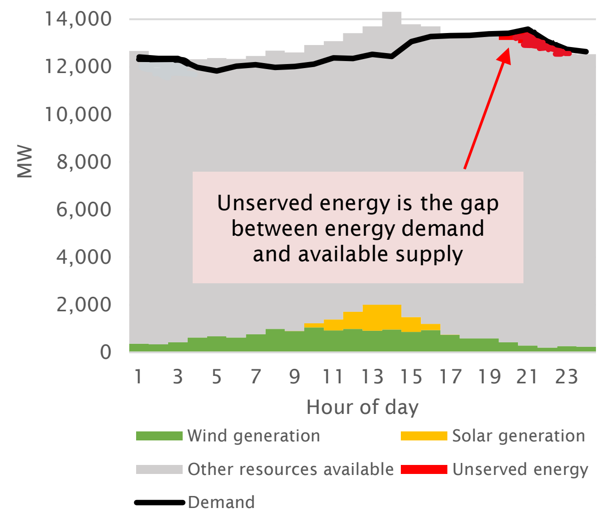
### Probabilistic supply adequacy analysis

- Only models specific years (2025, 2030, 2035, 2038, 2040)
- Each year is simulated 1,500 times under a combination of weather profiles and randomized maintenance/outages
- Focuses on frequency and distribution of unserved load events

# Supply adequacy is measured in terms of expected unserved energy (“EUE”), which is an industry standard metric in reliability analysis

- **Unserved energy refers to instances where not all customers’ electricity demand can be met**
  - When the system runs out of available supply to provide electricity to all customers, AESO would have to shed some load, which means some customers will not have electricity for some period of time
  - In the industry, this is sometimes referred to as a “rolling blackout”
- **Expected unserved energy is a metric to estimate the level of supply adequacy of an electric grid**
  - EUE is the estimated average MWh of unserved energy in a year
  - EUE has also been adopted by the AESO in its long-term supply adequacy analysis

**Illustration of unserved energy**




- **In LEI’s probabilistic supply adequacy analysis, the total unserved energy (in MWh) in each of the 1,500 runs for each modeled year is measured; EUE is the simple average of the unserved energy for those 1,500 runs**
- **Additional insights can be obtained through detailed analysis of modeled hours with unserved energy**

| Distribution of unserved energy | Duration of loss of load events | Magnitude of loss of load events | Analysis of severe loss of load events |
|---|---|---|---|
| ▪ Which season has the highest risk?<br>▪ Which hour of the day has the highest risk?<br>▪ What are the causes of unserved energy? | ▪ How many consecutive hours in a loss of load event? | ▪ How many MWhs of unserved load in a loss of load event?<br>▪ Unserved energy as a % of demand in that hour | ▪ In the 5% most severe loss of load events, what is the typical duration or typical % of demand unserved? |

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# The purpose of the probabilistic supply adequacy analysis is to understand the risks faced by the electric grid given the current market design

**1** **Results of LEI's supply adequacy analysis are based on the resource mix developed in the long-term analysis, which assumes continuation of the current market design**

- The resource mix is based on AESO's preliminary 2024 Long-term Outlook ("LTO")
- The current market design features an energy-only market with a $0/MWh price floor and $1,000/MWh price cap

**2** **This analysis focuses on supply adequacy at the hourly level, and does not study reliability risk at the sub-hourly level of grid operations**

- Unserved energy occurs when there are not enough resources to meet hourly demand
- Sub-hourly level of grid operational risk, such as need for additional ancillary services, is not modeled

**3** **LEI measures reliability risk in terms of energy, in the form of EUE; other costs of an unreliable grid are not modeled**

- Other costs of an unreliable grid include, but are not limited to, economic losses (due to business productivity interruptions), increase in the cost of doing business in Alberta (due to need to install backup generation), decrease in the quality of life, or even loss of human lives

**4** **There are options to reduce the EUE or limit the impact under the worst-case scenario**

- For example, in its preliminary 2024 LTO presentation, AESO discussed the use of electric vehicle ("EV") load shifting (load management) to mitigate reliability risk; other demand response and controllable load programs could also be helpful
- Modifications to the current market design could also result in a different supply mix, which may improve supply adequacy

**5** **It is outside the scope of this study to identify methods or market designs to reduce the forecasted reliability risks**

# Agenda

# Key inputs for the probabilistic supply adequacy analysis are built using real world electric system data, instead of relying on assumptions related to distribution and correlation of weather events

**Real world input data**

- Inputs sampled from actual weather data, yielding realistic representations
- Can accommodate multiple stochastic drivers – planned plant maintenance and unplanned outages – that resemble real world behaviour
- Provides a detailed representation of potential market outcomes with realistic weather-driven impacts

**Daily & hourly impacts**

- Adjusts for generation outages, different patterns of load, and intermittent (weather-dependent) renewable generation
- Transmission outages were not explicitly considered, but their effect on system operations is partially captured in the other data relied upon, including the historical import/export data and the historical renewable generation data*
- Represents real-world outcomes with net load and supply cushion variations

**Statistical analysis**

- Yields a distribution of potential market outcomes – supporting various statistical analyses and confidence level testing
- By simulating a large number of plausible scenarios, we no longer need to make *a priori* assumptions on the underlying distribution

* Transmission system outages, including outages on interties, impact reliability outcomes. If imports are not available for some period of time, and that coincides with other factors that cause a tight supply-demand condition on the electric grid, that may cause supply adequacy to further deteriorate. However, intertie outages were not considered in LEI's supply adequacy analysis. LEI modeled interties based on market opportunities – with more imports in higher priced hours and more exports in lower priced hours, as discussed in Annex 1 *(Scenario Analysis: Long Term Weather-Normal Energy Market Forecast).*

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# Using 2018-2022 actual load patterns and renewable capacity factors, LEI developed 25 synthetic weather profiles for assessing supply adequacy

## 1 Develop weather profiles based on historical data and AESO's load modifier forecasts

| | |
|---|---|
| **Load pattern** | ▪ Uses 2018-2022 hourly load shape<br>▪ Peak demand and total load scale with AESO preliminary 2024 LTO forecasts to account for demand growth<br>▪ Add back AESO preliminary 2024 LTO load modifiers to weather-adjusted demand forecast for future years |
| **Solar capacity factor** | ▪ Developed based on 2018-2022 hourly solar generation divided by installed solar capacity in the corresponding month |
| **Wind capacity factor** | ▪ Developed based on 2018-2022 hourly wind generation divided by installed wind capacity in the corresponding month |

## 2 5 actual weather profiles (2018-2022), split into weekly profiles

Weeks 1-52 in a year

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 Profile | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | … | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |
| 2019 Profile | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | … | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |
| 2020 Profile | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | … | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |
| 2021 Profile | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | … | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |
| 2022 Profile | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | … | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |

## 3 25 synthetic weather profiles based on randomized mix of weekly actual weather profiles

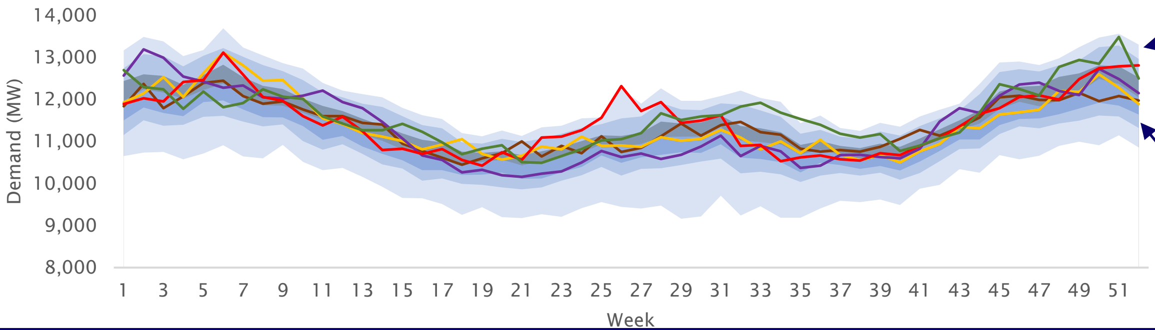
| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Synthetic 1 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | … | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |
| Synthetic 2 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | … | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |
| … | | | | | | | | | | | … | | | | | | | | | |
| Synthetic 24 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | … | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |
| Synthetic 25 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | … | 44 | 45 | 46 | 47 | 48 | 49 | 50 | 51 | 52 |

## 4 50 maintenance and forced outage "seed" runs on each of the 5 actual weather and 25 synthetic weather profiles

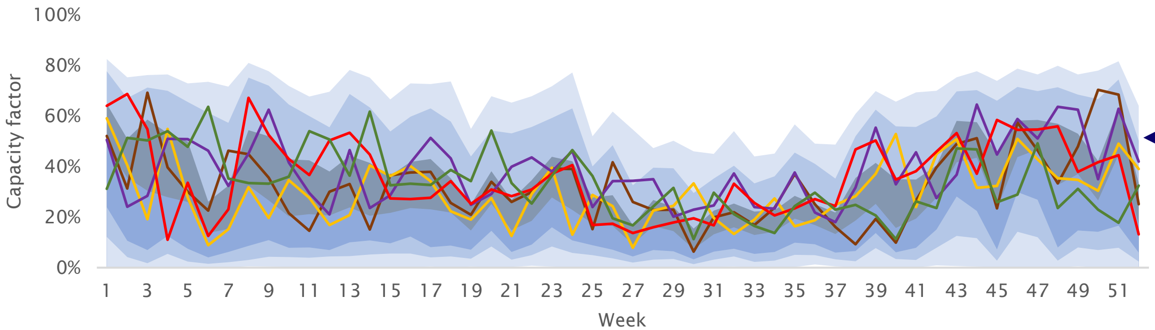
30 weather profiles x 50 outage seeds = 1,500 runs for each modeled year, allowing LEI to analyze the distribution of EUE events

# The synthetic weather profiles result in a diverse but realistic range of load and renewable generation profiles, as opposed to using the load and renewable generation profile of any single year

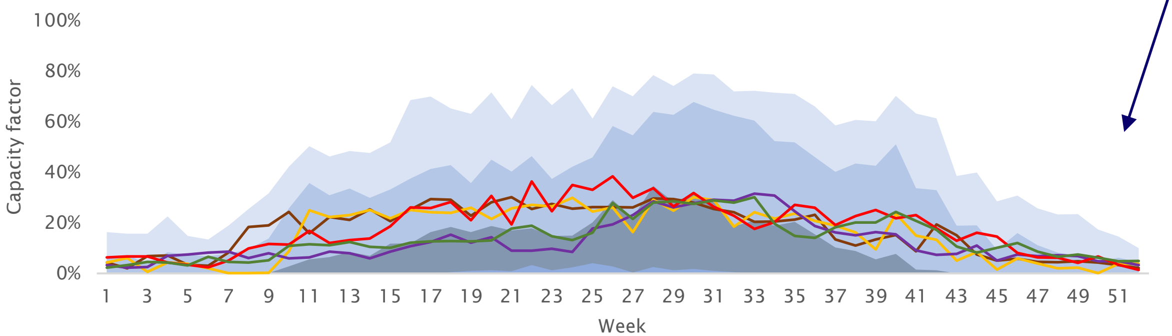
## Modeled range of weekly average on-peak demand (2038)




## Modeled range of capacity factors (by week) for existing wind




## Modeled range of capacity factors (by week) for existing solar




The shaded areas represent the 10th to 90th percentile hourly value of the week

For the demand shape, the 2018-2022 weekly averages represent the hourly average on-peak forecasted demand if the load pattern follows 2018-2022 historical data, adjusted for new demand drivers such as EVs and electrification of space heating

For wind and solar capacity factors, the 2018-2022 weekly averages represent the hourly average of 24x7 actual historical data

90%
80%
60%
40%
20%
10%
2018 weekly average
2019 weekly average
2020 weekly average
2021 weekly average
2022 weekly average

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# Agenda

| | |
|---|---|
| 1 | Modeling approach |
| 2 | Key assumptions and inputs |
| **3** | **Key modeling results** |

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# LEI performed the probabilistic supply adequacy analysis for 5 selected years out of the 20 years modeled in the long term weather-normal analysis

- **The probabilistic supply adequacy analysis is performed for selected years only due to the larger number of simulations required for each analyzed year**
- **Therefore, LEI performed the analysis at 5-year intervals (2025, 2030, 2035, and 2040), with one additional year (2038), as that is the year where all existing coal-to-gas units are assumed to retire**
  - For the Lower Demand Cases, only 2035 and 2038 are analyzed, as resource adequacy concerns as a result of demand shocks are expected to be minimal in 2025 and 2030

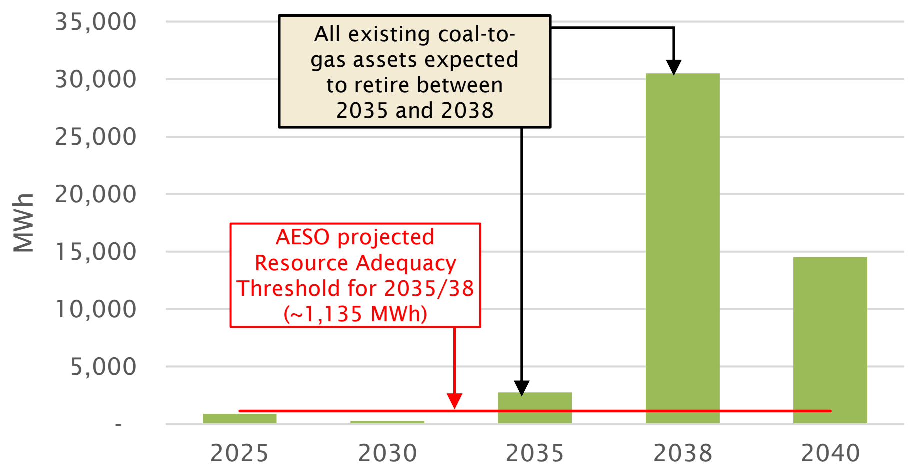
**Years and scenarios for which LEI conducted its probabilistic supply adequacy analysis**

| Scenario | 2025 | 2030 | 2035 | 2038 | 2040 |
|---|---|---|---|---|---|
| 2035 Base Case | ✓ | ✓ | ✓ | ✓ | ✓ |
| 2050 Base Case | ✓ | ✓ | ✓ | ✓ | ✓ |
| 2035 More Renewables Calibrated Case | ✓ | ✓ | ✓ | ✓ | ✓ |
| 2050 More Renewables Calibrated Case | ✓ | ✓ | ✓ | ✓ | ✓ |
| 2035 ~390 MW Lower Demand Case | | | ✓ | ✓ | |
| 2050 ~390 MW Lower Demand Case | | | ✓ | ✓ | |

# Under the 2035 Base Case, projected supply adequacy – in terms of EUE – reaches very high (unprecedented) levels in 2038 and 2040, indicating a high probability of load shed

- **Under LEI's 2035 Base Case, in 2035, with unabated assets limited to 450 hours of operation, modeled EUE across 1,500 weather runs reaches 2,754 MWh**
- **In 2038, modeled EUE across 1,500 weather runs reaches 30,491 MWh**
  - This is materially worse than the AESO's projected Resource Adequacy Threshold of approximately 1,135 MWh in 2038*
- **In 2040, modeled EUE declines to 14,533 MWh due to additional entry, but is still materially above the AESO's projected Resource Adequacy Threshold**

**Modeled EUE, 2035 Base Case with weather variability**




* Source: AESO. *2024 Long-term Outlook Preliminary Update.* November 15, 2023. The threshold is calculated as the 1-hour average Alberta internal load for a year divided by 10.

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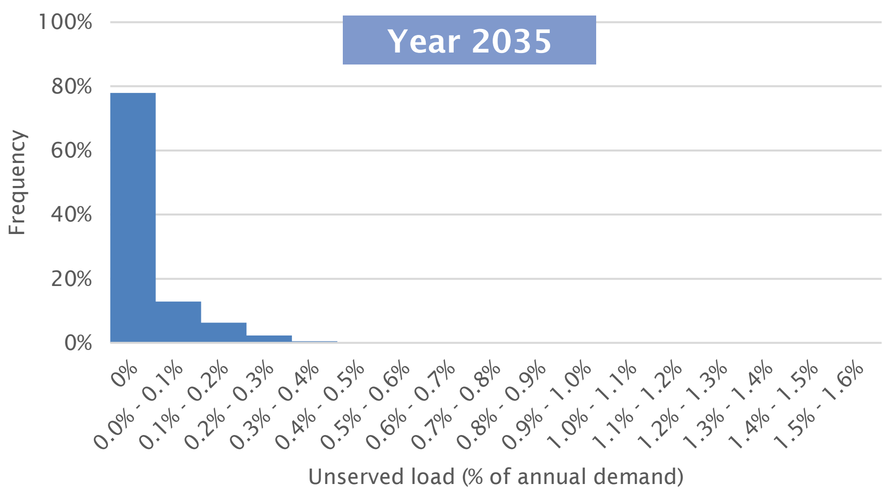
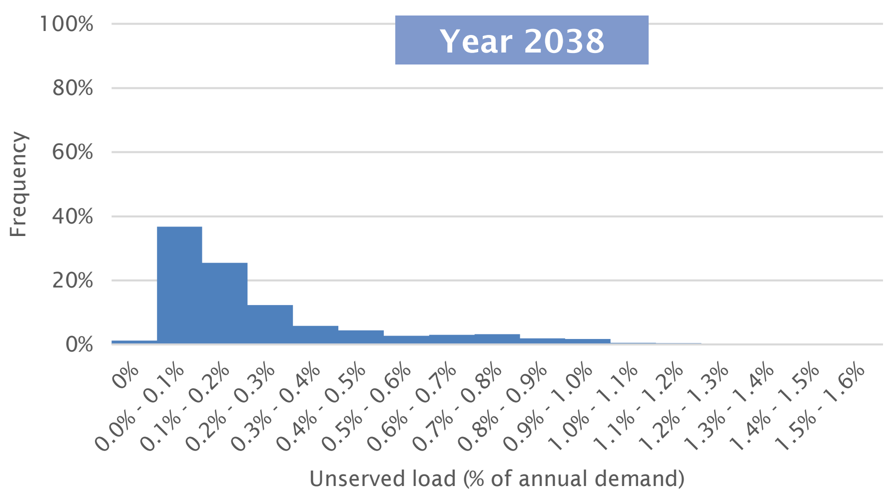
# LEI also assessed the distribution of projected EUE under the 2035 Base Case, in order to better understand the severity of potential load shed in 2035 and 2038

- **In 2035, nearly 80% of the 1,500 model runs result in no unserved load**
  - Conversely, around 20% of the model runs result in some unserved load
- **However, in 2038, only 1% of the 1,500 model runs result in no unserved load; for 37% of the runs, unserved load as a % of annual demand is less than 0.1%**
- **Furthermore, in 2038, for 1.3% of the 1,500 model runs, unserved load could exceed 1% of annual demand**

**Distribution of modeled unserved load under the 2035 Base Case with weather variability**



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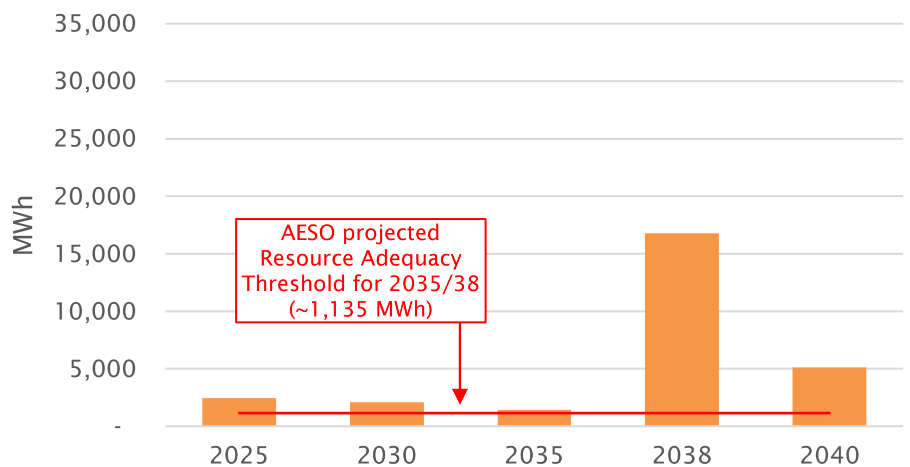
# Under the 2050 Base Case, projected EUE for 2038 and 2040 are better (more reliable) than the 2035 Base Case, but are still at unacceptable levels

- **Compared to the 2035 Base Case, the 2050 Base Case has worse resource adequacy in 2025 and 2030, because 2 additional coal-to-gas units are assumed to retire before 2025 under AESO's Decarbonization by 2050 scenario (see next slide for more details)**
- **Under LEI's 2050 Base Case, in 2035, modeled EUE across 1,500 weather runs reaches 1,420 MWh**
- **In 2038, modeled EUE across 1,500 weather runs reaches 16,793 MWh**
  - 2050 Base Case has relatively better supply adequacy than the 2035 Base Case; however, still materially worse than the AESO's projected Resource Adequacy Threshold of approximately 1,135 MWh in 2038*
- **In 2040, modeled EUE is estimated at 5,127 MWh – still above AESO's projected Resource Adequacy Threshold**

**Modeled EUE, 2050 Base Case with weather variability**




* Source: AESO. *2024 Long-term Outlook Preliminary Update.* November 15, 2023. The threshold is calculated as the 1-hour average Alberta internal load for a year divided by 10.

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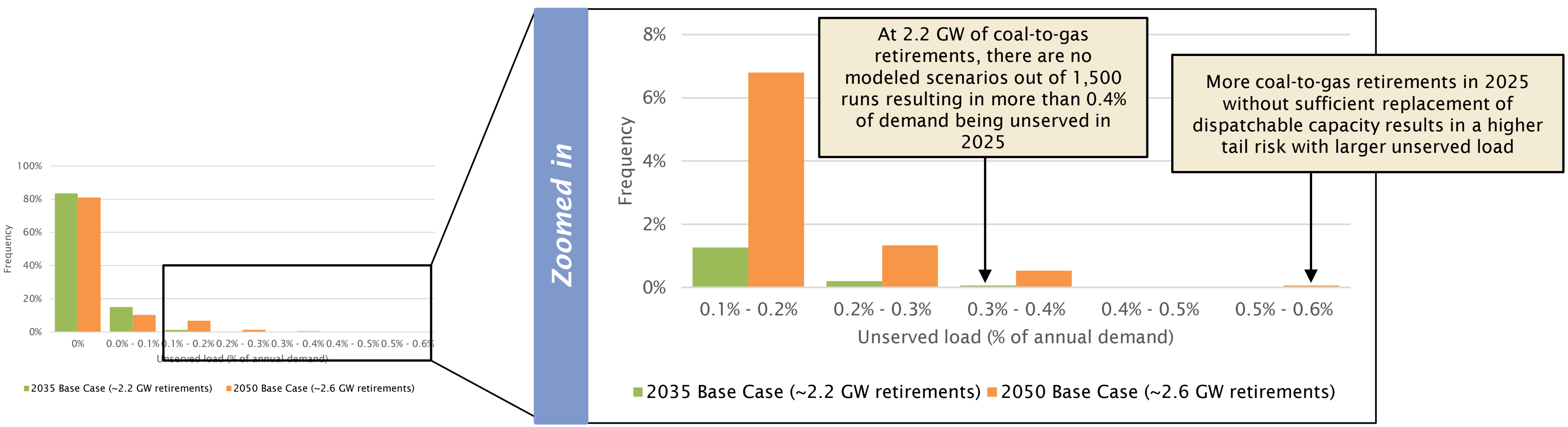
# More coal-to-gas retirements in the near term without sufficient replacement capacity results in increased risk of unserved load (coupled with abnormal weather)

- **AESO assumes all coal-to-gas units (totaling ~4 GW) would retire by the end of 2037**
- **However, the schedule of retirements differs between AESO's Decarbonization by 2035 and Decarbonization by 2050 scenarios**
  - ~2.2 GW (56%) of these coal-to-gas units retire in 2024 under AESO's Decarbonization by 2035 scenario
  - In comparison, ~2.6 GW (66%) retire in 2024 under AESO's Decarbonization by 2050 scenario
  - 2.9 GW of new dispatchable capacity is added from 2023-2025, consistent with the AESO's supply projections, resulting in a net increase in dispatchable capacity, which is less than forecasted demand growth over the same period of time
- **Under the 2050 Base Case, LEI's modeled EUE in 2025 with 2.6 GW of coal-to-gas retirements reaches 2,450 MWh, exceeding both AESO's LTO Resource Adequacy threshold (1,135 MWh) and Two-Year Probability of Supply Adequacy Shortfall Metric from Nov. 2023 (2,005 MWh)**

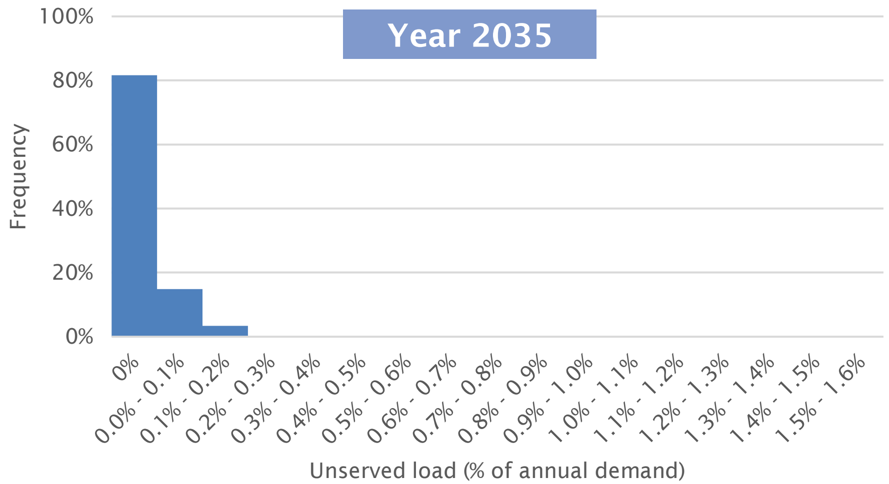
**Distribution of modeled unserved load in 2025 under different coal-to-gas retirement schedules**

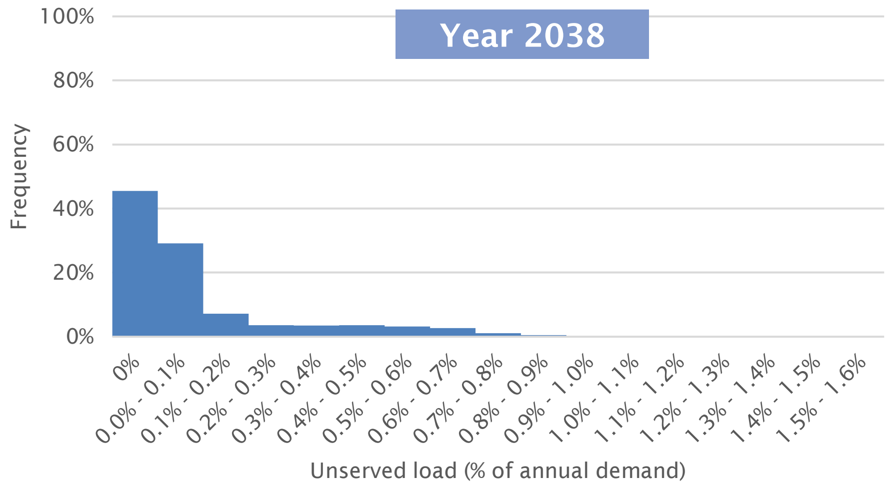


# LEI assessed the distribution of projected EUE under the 2050 Base Case, which demonstrates less severe modeled unserved load in 2038 as compared to the 2035 Base Case

- **In 2035, over 80% of the 1,500 model runs result in no unserved load**
  - Conversely, around 20% of the model runs result in some unserved load
- **However, in 2038, only 45% of the 1,500 model runs result in no unserved load**

**Distribution of modeled unserved load under the 2050 Base Case with weather variability**



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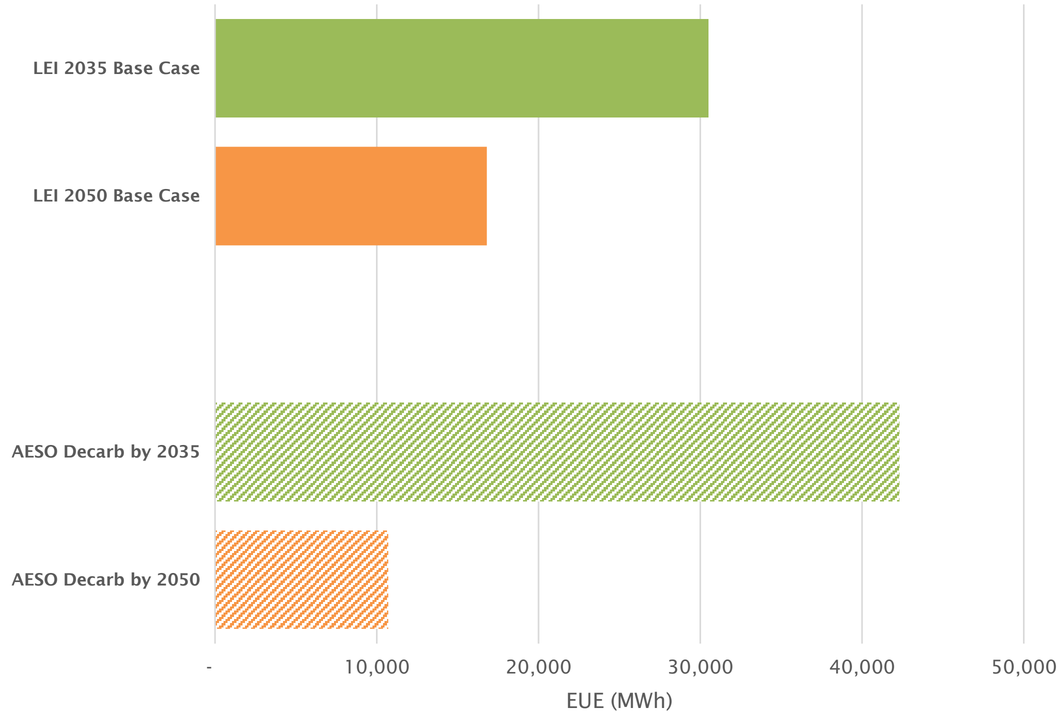
# LEI's modeled EUE in both the 2035 Base Case and 2050 Base Case are comparable with the AESO's modeled EUE in its preliminary 2024 LTO

**Forecasted EUE in 2038, LEI vs AESO preliminary 2024 LTO (MWh)**




- **Some differences between LEI and the AESO's EUE results are to be expected – LEI and the AESO rely on different inputs related to weather, outages, and hourly demand shape**
- **Despite inherent differences in modeling inputs, LEI's results are aligned with the AESO's EUE results – both demonstrate increasing EUE from the 2050 scenarios to the 2035 scenarios; both also demonstrate similar levels of EUE across comparable supply-demand scenarios**

Source: AESO. *2024 Long-term Outlook, Preliminary Update.* November 15, 2023.

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# Alberta’s system is forecast to have the highest unserved energy risk in winter evenings, with highest risk hours in December from 6-9 pm

- **In the 2035 Base Case, nearly 20% of unserved energy events occur in December (6-9pm)**
- **Unserved energy events occur when there is a combination of very low wind generation, no solar generation (during nighttime), high demand, and higher than average generation asset outages**

## Monthly and hourly distribution of modeled unserved load in 2038 (2035 Base Case)

Hour of day

| Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 | 0.00 | 0.01 | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.02 | 0.05 | 0.07 | 0.09 | 0.09 | 0.09 | 0.07 | 0.06 | 0.03 |
| February | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.01 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.06 | 0.07 | 0.07 | 0.07 | 0.06 | 0.05 | 0.01 |
| March | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| April | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| May | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| June | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| July | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| August | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| September | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| October | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| November | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.07 | 0.07 | 0.07 | 0.07 | 0.06 | 0.05 | 0.02 |
| December | 0.04 | 0.03 | 0.02 | 0.02 | 0.02 | 0.01 | 0.01 | 0.06 | 0.06 | 0.05 | 0.04 | 0.04 | 0.03 | 0.03 | 0.03 | 0.07 | 0.14 | 0.17 | 0.17 | 0.17 | 0.17 | 0.14 | 0.15 | 0.07 |

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# In the top 5% worst situations modeled, an average of ~10% of demand would be unserved, with events on average lasting for almost an entire day (23 hours)

- **For reference, Storm Uri in 2021 resulted in an estimated load shed of up to 26% of demand in Texas; load shed lasted for ~72 hours**
  - The Electric Reliability Council of Texas ("ERCOT") estimated that 20,000 MW out of ~76,000 MW of demand was shed during the highest demand hour on February 15, 2021

**Summary of average and 5% worst case EUE, MW of unserved load, and duration of unserved load**

| EUE (MWh) | 2025 | 2030 | 2035 | 2038 | 2040 |
|---|---|---|---|---|---|
| 2035 Base Case | 872 | 271 | 2,754 | 30,491 | 14,533 |
| 2050 Base Case | 2,450 | 2,103 | 1,420 | 16,793 | 5,127 |
| AESO forecasted Resource Adequacy Threshold* | 2,005 | | 1,135 | 1,135 | |

| Average MW of unserved load during outage events (MW) | 2025 | 2030 | 2035 | 2038 | 2040 |
|---|---|---|---|---|---|
| 2035 Base Case | 292 | 256 | 410 | 473 | 408 |
| 2050 Base Case | 357 | 356 | 335 | 430 | 344 |

| Worst 5% event** average unserved load duration (hours) | 2025 | 2030 | 2035 | 2038 | 2040 |
|---|---|---|---|---|---|
| 2035 Base Case | 12.9 | 10.1 | 15.5 | 23.0 | 15.7 |
| 2050 Base Case | 15.2 | 13.1 | 11.2 | 19.0 | 11.8 |

| Worst 5% hours** average unserved load (MW) | 2025 | 2030 | 2035 | 2038 | 2040 |
|---|---|---|---|---|---|
| 2035 Base Case | 981 | 815 | 971 | 1,034 | 985 |
| 2050 Base Case | 1,088 | 1,045 | 1,043 | 1,245 | 1,208 |

| Worst 5% hours** average % of demand unserved (%) | 2025 | 2030 | 2035 | 2038 | 2040 |
|---|---|---|---|---|---|
| 2035 Base Case | 8.3% | 6.7% | 7.5% | 7.9% | 7.2% |
| 2050 Base Case | 9.3% | 8.7% | 8.1% | 9.4% | 8.7% |

* Note 1: In 2025, modeled EUE for the 2050 Base Case is higher than the threshold value published in the AESO's November 2023 Long-Term Adequacy ("LTA") Report – this is because LEI's 2050 Base Case assumes over 3 GW of coal-to-gas unit retirements by 2025, while AESO's November 2023 LTA only assumes 820 MW of coal unit retirements.

** Note 2: The 5% worst events are measured for average unserved load duration, average unserved load MW, and % of demand unserved; these do not necessarily correspond to the same events – some events may be long but with small MW unserved, other events may be short but with large MW unserved.

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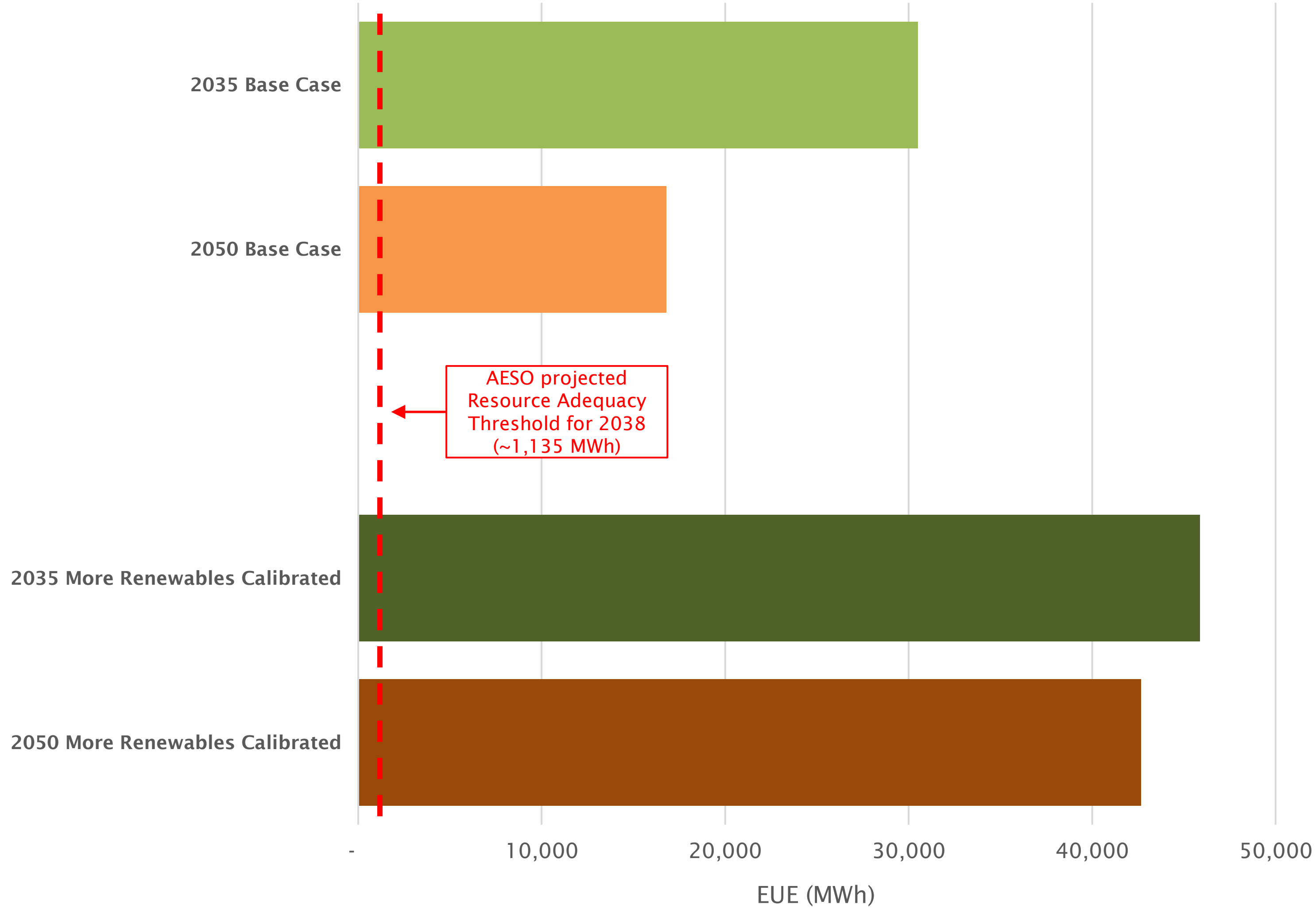
# LEI's More Renewables Calibrated Cases are projected to result in lower levels of supply adequacy (higher levels of EUE), because lower profits in the energy market result in less CCGT new entry / earlier retirements

## Forecasted EUE in 2038 under different scenarios (MWh)



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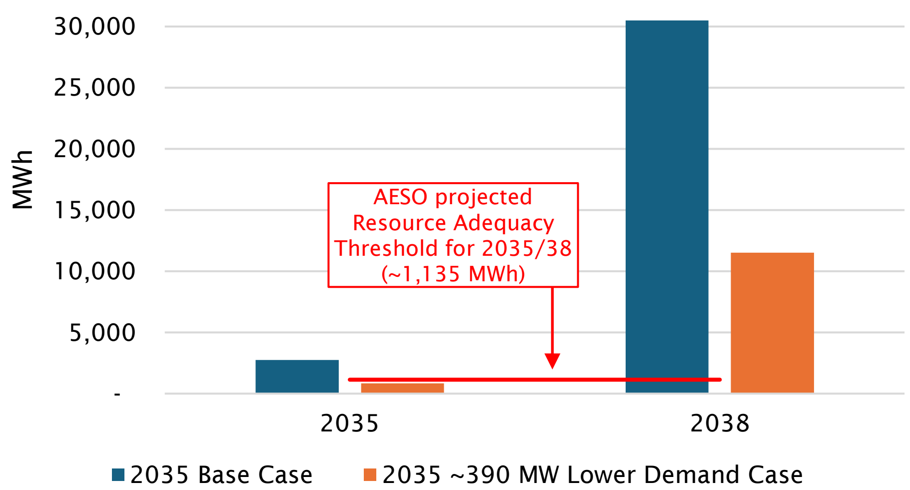
# Holding supply conditions constant, lower demand results in better reliability; however, in 2038, the 2035 ~390 MW Lower Demand Case still results in reliability that is worse than the AESO's current standard

- **A negative demand shock of 3.5% reduces the EUE in the Decarbonization by 2035 scenario materially**
- **In 2035, EUE decreases from 2,754 MWh to 857 MWh, bringing the EUE in the 2035 ~390 MW Lower Demand Case to below AESO's projected Resource Adequacy Threshold**
- **In 2038, EUE decreases from 30,491 MWh to 11,524 MWh under the 2035 ~390 MW Lower Demand Case, which is still significantly higher than the AESO's projected Resource Adequacy Threshold**
  - An estimated additional 800 MW of demand reduction over the 2035 ~390 MW Lower Demand Case (i.e., ~1,200 MW over the 2035 Base Case) is needed to reduce the EUE to below the Resource Adequacy Threshold

**Modeled EUE, Decarbonization by 2035 (MWh)**



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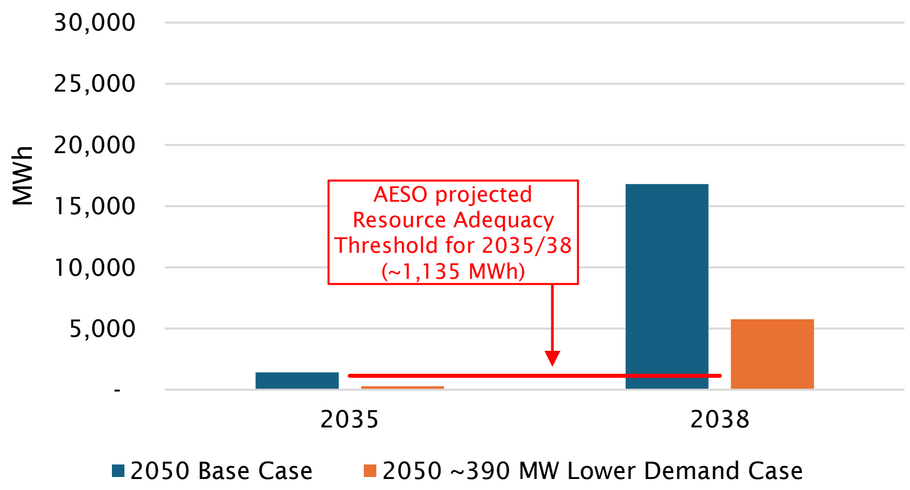
# Similarly, in 2038, the 2050 ~390 MW Lower Demand Case still results in reliability that is worse than the AESO's current standard

- **In 2035, EUE decreases from 1,420 MWh to 308 MWh, bringing the EUE in the 2050 ~390 MW Lower Demand Case to below AESO's projected Resource Adequacy Threshold**
- **In 2038, EUE decreases from 16,793 MWh to 5,755 MWh under the 2050 ~390 MW Lower Demand Case, which is still significantly higher than AESO's projected Resource Adequacy Threshold**
  - An estimated additional 550 MW of demand reduction over the 2050 ~390 MW Lower Demand Case (i.e., ~850 MW over the 2050 Base Case) is needed to reduce the EUE to below the Resource Adequacy Threshold

**Modeled EUE, Decarbonization by 2050 (MWh)**



# Glossary of key terms

**AESO's Resource Adequacy Threshold:** The AESO develops a Long Term Outlook every two years to forecast electricity demand and generation over a 20-year horizon to inform its long-term plans. The LTO monitors resource adequacy through a Resource Adequacy Threshold. This analysis is conducted for information and planning purposes only – there is no mechanism for the AESO to procure new generation even if reliability risk is found to exceed the threshold.

**AESO's Supply Adequacy Shortfall Metric:** While the Alberta energy-only electricity market has no mandated reliability targets, the AESO is still required to report on long-term (2 year) resource adequacy metrics on a quarterly basis. If the AESO identifies a two-year probability of supply adequacy shortfall, the AESO may take specific preventative actions, including procuring load shed services, back-up generation, or emergency portable generation.

**Expected unserved energy ("EUE"):** EUE is a metric to estimate the level of supply adequacy of an electric grid. It is the estimated average MWh of unserved energy in a year.

**Load shed:** As a result of unserved load, a system operator would have to shed some load – which means that some customers will not have electricity for some period of time. In the industry, this is sometimes also referred to as a "rolling blackout".

**Rolling blackout:** A rolling blackout entails the system operator intentionally cutting electricity to some customers in order to balance supply and demand. A rolling blackout is therefore a partial outage of the electric system – in contrast with a system-wide blackout, where the entire system is on outage.

**Supply adequacy:** Supply adequacy is having enough electricity generation supply to meet hourly demand, taking into account planned and unplanned outages and other factors that may impact demand or supply. Supply inadequacy is one cause of poor system reliability.

**System reliability:** System reliability is broader than supply adequacy and includes elements such as inertia and frequency support. In other words, supply adequacy is a component of system reliability. Other components of system reliability include the ability to continuously balance supply and demand and maintain adequate inertia and frequency on the grid.

**Unserved load/unserved energy:** Unserved load (or unserved energy) refers to instances where not all customers' electricity demand can be met, regardless of price. It can be measured in MWh or % of annual demand not met, which is the amount of demand that is not served when the system runs out of available supply to provide electricity to all customers.

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# Bibliography of information and data sources relied upon for LEI's supply adequacy assessment


AESO. *Long-Term Adequacy Metrics.*

AESO. *Long-Term Adequacy Metrics, Threshold and Threshold Actions Recommendation Paper.* February 7, 2008.

AESO. *Long-Term Outlook Resource Adequacy – CER Assessment.* September 27, 2023.

AESO. *Resource Adequacy Model and Gross Minimum Procurement Volume Technical Report.* May 31, 2019.

Historical hourly demand, wind and solar generation from AESO *ETS API.*

Lawrence Berkeley National Laboratory. *A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and technical dimensions.* June 2023.

National Association of Regulatory Utility Commissioners. *Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms.* November 2023.

North American Electric Reliability Corporation. *2022 Long-Term Reliability Assessment.* December 2022.

# Disclaimer notice

**While LEI has taken all reasonable care to ensure that its analysis is complete, power markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Investors, lenders, and others should note that:**

- No results provided or opinions given in LEI's analysis should be taken as a promise or guarantee as to the occurrence of any future events.
- There can be substantial variation between assumptions and market outcomes analyzed by various consulting organizations specializing in competitive power markets and investments in such markets. Neither LEI nor its employees make any representation or warranty as to the consistency of LEI's analysis with that of other parties.
- LEI's analysis is not intended to be a complete and exhaustive analysis of future market outcomes. All possible factors of importance to a potential investor have not necessarily been considered. The provision of an analysis by LEI does not obviate the need for potential investors to make further appropriate inquiries as to the accuracy of the information included therein, and to undertake their own analysis and due diligence.

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Alberta Utilities Commission

FEBRUARY 2024

# *Market Perception* Study

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# Executive Summary

## The Alberta Utilities Commission commissioned a market perception study from Longview Communications and Public Affairs (recently renamed "FGS Longview"[1]) to review the attractiveness of Alberta's power market from an investor perspective, identify the drivers behind changes in stakeholder perceptions, and assess investor views on potential market design changes.

FGS Longview conducted interviews with stakeholders in Alberta's power market, including capital providers, incumbent and prospective developers of renewable and thermal generation in Alberta, industry analysts and Indigenous participants in energy and infrastructure projects. The following is a summary and overview of the primary conclusions of those interviews.

**It is important to note that this report presents the views shared by the study participants. It makes no recommendations nor does it reach any conclusions or offer a view on government policy choices, which must take into account a wide range of stakeholder interests. Investment considerations should be viewed in this broader context.**

**Stakeholder perception of Alberta's power market is highly varied and changing rapidly.** Study participants identified numerous factors that contributed to their historical and current outlook on the attractiveness of Alberta's power market. However, one factor stood out as a key driver of changing stakeholder perception among all participant groups: policy uncertainty.[2]

**Policy uncertainty is leading to a reduction in appetite for investment from both incumbent and non-incumbent generators as well as from providers of capital.** Participants in the study agreed that policy uncertainty has increased over the past decade, which prevents prospective investors from accurately projecting future market and policy environments, and modelling project revenues based on those projections. Participants in the study do not uniformly agree on who bears the responsibility for creating this uncertainty, with participants suggesting a variety of responsible parties. However, participants were aligned on the assertion that a more coordinated and measured approach from all parties would support a more constructive environment for investment in Alberta.

Participants were in general agreement that the existing energy-only model is well positioned to deliver on concurrent goals of emissions reduction and affordability, but many participants indicated that the existing market framework was not set up to deliver on reliability. Despite this, most participants indicated a preference for minor revisions to the energy-only model to competitively procure reliability services over substantive market reforms such as capacity markets or provincial Crown corporations. Participants expressed concern over the considerable time required to implement market design reforms, as well as varying degrees of conviction that other market designs would deliver better reliability outcomes than the energy-only market.

Finally, most participants indicated that their primary concerns with the Alberta power market were short-term, stemming from uncertainty around unfinalized Clean Electricity Regulations ("CER"), the provincial pause on renewable energy development, and other policy proposals being considered at the federal and provincial levels. **Participants largely agreed that, over the long term, when federal environmental legislation is finalized and provincial questions around potential market reforms are answered, Alberta would continue to be an attractive market for investors.** However, if policy uncertainty persists in the long run, Alberta will likely continue to face a reduction in investor appetite for participation in new generation projects.

1 During the study period, Longview concluded a transaction in which it was acquired by FGS Global and commenced operations as FGS Longview. For the purposes of this report, the term "FGS Longview" will be used throughout.

2 Participants in this study frequently used the terms "regulatory uncertainty" and "policy uncertainty" interchangeably. For the purposes of this report, both terms were understood to mean policy uncertainty unless a participant is referring to specific regulations governing Alberta's power market.

# Background and Process

## OVERVIEW

The market perception survey was commissioned by the Alberta Utilities Commission ("AUC") under its Inquiry into the ongoing economic, orderly, and efficient development of electricity generation in Alberta. Under Module B of the Inquiry, the AUC commissioned two separate entities to prepare research reports independent of one another, focused on the qualitative and quantitative impacts of the increasing growth of renewables on both generation supply mix and electricity system reliability.

The goal of the survey was to assess the attractiveness of the Alberta power market, views on potential market structure changes, and appetite for merchant power risk by relevant generation developers (incumbent and non-incumbent) and sources of capital. Following a competitive submission process, FGS Longview was commissioned to prepare the qualitative report based on long-form, open-ended interviews with volunteer participants.

## STUDY DESIGN

**The survey targeted a variety of participant categories from the investment community, from operators of generation facilities in the province and from Indigenous participants in energy and infrastructure projects.** The initial list of potential participants was developed by FGS Longview in conjunction with the AUC. Some participants were included through recommendations by other participants, or through their own direct requests to the AUC or FGS Longview to be included in the Inquiry.

All participants provided useful stakeholder perspectives on the investibility of the Alberta power market.

Within the investment community, participants included institutional providers of debt and equity capital[3], as well as research analysts employed by investment dealers specializing in utilities and power generation companies. The capital providers were included because of their access to capital and their exposure to investment opportunities throughout the industry and in many jurisdictions. The research analysts were included for their deep knowledge of the industry across multiple jurisdictions and frequent engagement with hundreds of institutional investors, providing research and investment recommendations on a regular basis.

Within the generators, participants included those exclusively in the power business as well as participants who were also consumers of electricity in the province. There was also meaningful input from those who were either Indigenous or worked closely with Indigenous communities to support Indigenous participation in energy and infrastructure projects, as well as an industry association representing members in the power generation business. More detail on the breakdown of participants is available below.

The survey questions were prepared by FGS Longview in consultation with the AUC. Survey questions were customized to target the area of interest for each category of participant. The survey primarily focused on the following topics:

- Background and nature of participation in the Alberta energy market
- Current views on the Alberta economy and the attractiveness of Alberta's power market
- Impact of regulatory/market structure considerations on investment intentions
- Views on potential market design changes
- Policy considerations for capital markets respondents
- Investment considerations for power generators
- Considerations in the investment decision-making/valuation processes

## STUDY PROCESS

During the course of interviews, FGS Longview contacted 111 potential participants of which 44 participated in 30 interviews. These interviews all took place between November 10 and December 21, 2023, with the exception of one interview in January 2024. Interviews were held over Zoom with at least two interviewers per session. Participants were offered the opportunity to comment for attribution or to remain anonymous. Almost all participants agreed to take part on the condition of anonymity. The sessions were recorded and transcribed for accuracy. To preserve confidentiality, all copies of the recordings will be deleted upon submission of the final report. Themes and findings were analyzed within each participant group, but responses may be aggregated on questions where they are aligned.

3 Definitions of these terms are available in the Glossary section of this report.

## PARTICIPANTS

### INVESTMENT COMMUNITY

**Capital Providers (afterwards known as "Investors")**

This group had invested equity or debt capital in the Alberta power market and are potential providers of future capital. There were 12 participants in a series of 8 interviews offering 9 separate perspectives. The participant mix included representatives from private investment counsellors (4), bank-owned investment managers (4) and insurance companies (4). The remaining data is based on the nine unique respondents.

Total assets under management at the organizations ranged from $30 billion to $200 billion. Most of the investors managed assets across multiple mandates including retail mutual funds, institutional pooled and segregated funds, insurance company funds and dedicated project finance portfolios.

Participants offered a diversity of exposures including holding equities in public utilities (2), bonds in public utility companies (4) and non-public utilities (1) or non-specific exposure ranging from $50 million to $3 billion across the sector (3).

**Industry Analysts**

Participants in this group included representatives of four of the top five major Canadian banks. They either had primary research coverage of Canadian utilities and power producers or were involved in structuring capital transactions on behalf of public and private issuers. There were seven (7) participants in a series of six (6) interviews. For the purposes of this survey, the two (2) respondents in one interview offered a shared perspective and will be counted as one (1) participant.

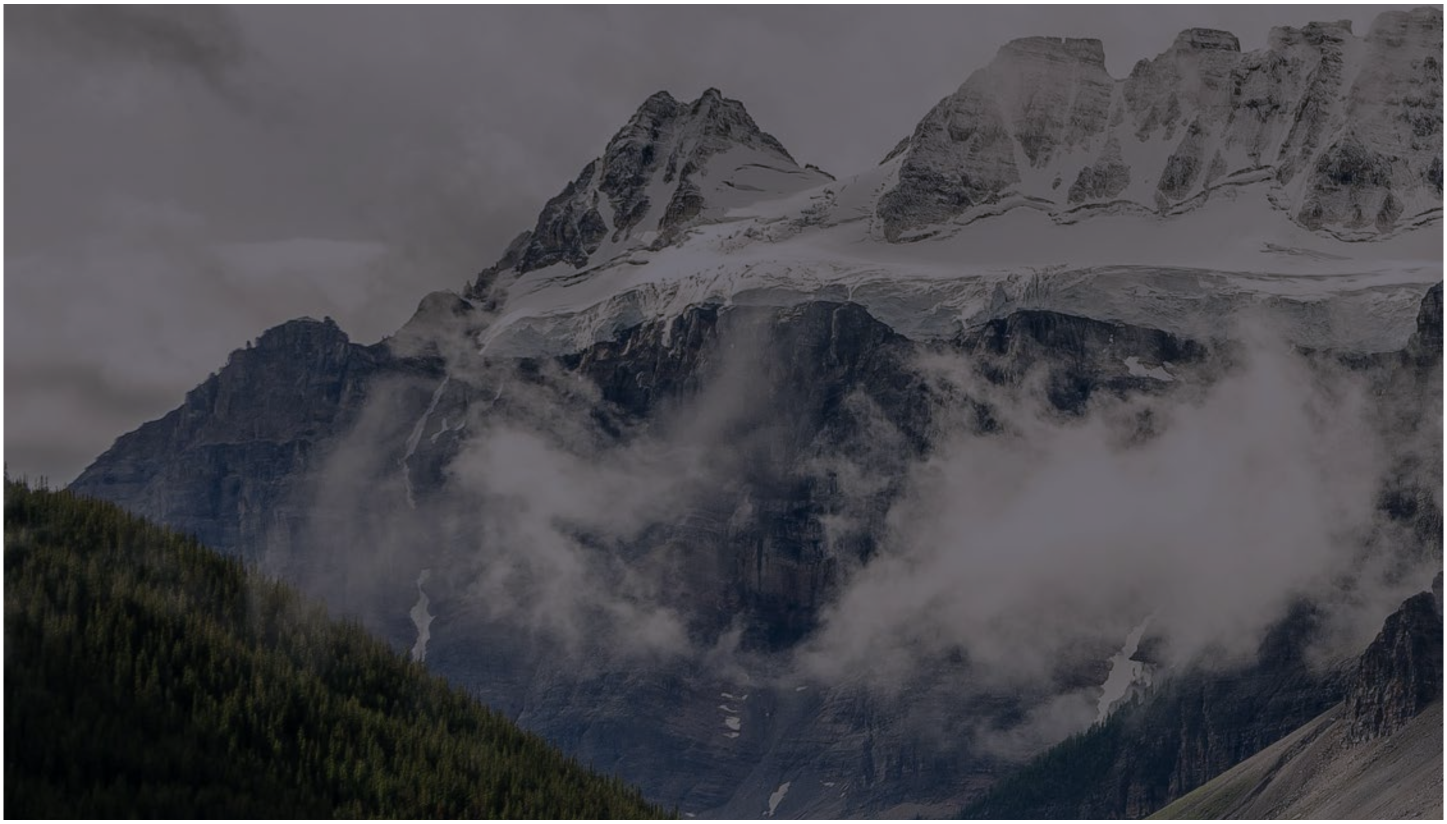
The participants had a diverse range of research coverage responsibilities which included regulated utilities, pipelines, and independent power producers, within Canada and North America.

**Power Generators**

Participants in this group included twenty-three (23) individuals representing fourteen (14) companies or associations. For this report, the comments of multiple individuals representing one company have been reflected as the comments of one participant. Five (5) individuals representing three (3) companies or associations were exclusively in the business of renewable energy. Seven (7) individuals representing three (3) participants had existing investments across a diverse portfolio of generation technologies, including both renewable and thermal generation. Eleven (11) individuals representing eight (8) companies were exclusively in the business of thermal generation. For the remainder of this report, the "participant" refers to the company or association, not the individual.

**Indigenous Market Participants**

Two participants in the study were representatives of a First Nation or work closely with Indigenous communities to support Indigenous participation in energy and infrastructure projects.



# Participant Feedback

The following sections set out the responses from participants to questions on various aspects of the Alberta power market that contribute to an overall view on investibility. The feedback represents the opinions of the different participant groups as presented.

## MARKET OUTLOOK

All participants were asked to describe their current outlook for the Alberta power market, identify if their outlook had changed substantially in recent years, and specify the drivers behind any changes in outlook.

### INVESTORS

When asked for an unprompted assessment of the Alberta economy and the Alberta power market, participants offered the following observations:

#### Link to energy industry

The most commonly identified feature of the Alberta economy was the link between Alberta's economy and the movement in energy prices. Although energy had been a source of growth in the province in the past, this link was now seen as a source of increased risk compared with other jurisdictions due to a) higher volatility in the economy due to the cyclicality of energy prices, and b) the risk to the energy sector from the transition away from fossil fuels.

> “There was a lot of pain and a lot of difficulty in with respect to decarbonization and investing in coal has been a difficult space and [we are getting] a lot of pushback there and we're getting increasing pushback on the natural gas side from investment committee. Looking at gas more cautiously than in the past.

#### Power market uncertainties

Looking at the power market in Alberta, the most common investor response cited the nature of merchant contracts in Alberta as a source of concern due to the perceived lower credit quality of merchant contracts as determined by internal risk ratings or third-party credit rating agencies. Many investors were supportive of the transition away from coal but were concerned about overbuilding of new supply. In particular, a few participants indicated concerns regarding the increasing percentage of renewables creating price volatility and grid instability.

> “Even going back more than 10 years, the AESO itself pointed out that the more non-dispatchable assets you add to the grid, the harder it is to maintain grid stability.

#### Regional comparison

When asked to compare Alberta with other jurisdictions for power market investments, participants frequently cited lower credit quality of merchant contracts in Alberta. For some investors, the lower quality of merchant contracts precluded any investment in renewable power whilst others said they would require some form of compensation for the higher risk in the form of higher spreads, shorter-term contracts, or lower debt component in the funding structure. All these types of compensations would increase the cost of constructing power generation in Alberta relative to other markets.

> “[In] Alberta, if you're lucky, you can get 50 cents on the dollar of leverage versus if you're an IPP and you're doing a wind project in Ontario, you can probably get 90 cents of it borrowed and only have to put in 10.
>
> And so, the way I would look at it is…from an owner standpoint, the inability to leverage your capital to build a plant in Alberta -that means that again, you're using the highest cost of capital in equity.

Many investors also cited Alberta as having an increased risk of stranded assets relative to other jurisdictions. Some investors cited the risk of investor losses due to catastrophic events. Some investors cited a history of losses to investors from changes in policy treatment.

### INDUSTRY ANALYSTS

#### Favourable view of the economy

When asked about their current views of the Alberta power market and economy specifically, participants largely agreed that Alberta is seen as a largely favourable market due to the improving economy and job opportunities, investments in decarbonization, infrastructure growth and high load growth, robust economy for renewables and the fact that firms have been able to optimize existing assets. The link to the health of the energy sector was seen as a positive contributor to economic growth. Some respondents also mentioned that industry is healthy, and companies under coverage have strong balance sheets.

**History of policy and regulatory uncertainty**

There was general agreement on the need for policy certainty. Several respondents mentioned there is uncertainty in the market and expressed concern that the economic life of legacy assets may not translate into new market structures. Other respondents expressed concern about current and past levels of government involvement in setting market structures. A small subset of the participant group added that regulatory decisions have not always been timely to the detriment of market participants. Another small subset was hopeful that the Inquiry process would lead to improved policy clarity and transparency.

Several participants referred to the Inquiry itself and the pause on approvals of renewable projects. Few participants suggested that companies should suspend decisions on new investments until the new market structure was announced. Others were hopeful that the moratorium would be temporary and that good opportunities for investment in renewable generation would follow in time. A small subset of the participant group expressed concern about future oversupply.

**Shifting market outlook**

When asked if respondents views on the Alberta power market have changed in the past five years, all participants who responded referred to increasing uncertainty. Sources of that uncertainty included:

- The end of the balancing pool
- Changes in government affecting the economics of an investment in power
- The current policy "squabble" between the provincial and federal governments
- Introduction of Clean Electricity Regulations

Several respondents pointed out the specific risks of overbuilding of renewables capacity causing more zero-priced hours and hurting grid reliability. Others said that it was becoming more difficult to make investment decisions due to increasing policy uncertainty. By contrast, a small subset said they had become more of a believer in the ability of the energy-only market to incent renewables construction.

**Regional comparison**

When asked how Alberta compares with other jurisdictions for investing in power projects and if there are differences between variable, baseload and dispatchable power, participants' answers demonstrated that the dynamics of Alberta can be seen as both a help and a hindrance. A few respondents said Alberta was a more challenging place to build projects because a lack of contract certainty made the project economics riskier, whilst other markets have mechanisms to incent generation with government-sponsored Crown corporations. Alternatively, some saw the ability to partner with the private sector as a positive, as government involvement was seen as a source of delay and cost escalation.

**POWER GENERATORS**

**Investibility today**

Within this group, perspectives varied on the investibility of the Alberta power market in both the near term and the long term. A majority of the participants affirmed that the Alberta power market was investible or that they were currently exploring new generation projects.

> “Generally speaking, we're very bullish on the future of renewables, not only in Alberta but in Canada. I think the sky is the limit to achieve climate change targets.

Several participants said the Alberta power market was not investible in the short term but could be in the long term. A small number of participants said that renewables were investible, but thermal generation was "challenging." A small number of participants indicated the Alberta power market was not investible.

**Concern for power prices**

Many participants indicated that they expected power prices to decline in 2024 and 2025, driven by significant capacity additions of both thermal and renewable generation. A small subset of the participant group, including one of the representatives of a large, diversified operator stated that there was no need for additional investment in supply—renewable or thermal—on a short-term basis because expected capacity additions in 2024 and 2025 would meet current electricity demand.

> “Alberta is full.

**Impact of policy uncertainty**

Participants invested in **renewable energy** indicated that the appetite for corporate power purchase agreements remained strong and investment would likely continue after the pause on approvals ends, depending on the outcomes of the Inquiry. Participants invested in **thermal generation** indicated that future investment decisions were more challenging than in recent years. This is attributed to overlapping and unfinalized regulations that make it difficult to model project revenues with any certainty.

Policy uncertainty was the most frequently cited factor having a negative impact on the participants' market outlook. All participants interviewed identified that increasing policy uncertainty negatively impacted their outlook for the Alberta power market. In general, the interviewed participants did not attribute blame for causing this uncertainty to any individual government, department, agency, policy, or regulation.

**Rather, there was a consensus that it was the lack of agreement across governments, departments, and agencies that most significantly contributed to policy uncertainty.** Participants indicated that the inability to understand and model future policy environments with any certainty inhibits them from modelling projected cash flows. Different participants identified the Government of Alberta, the Government of Canada, the Alberta Utilities Commission, and the Alberta Electric System Operator all as contributors to this lack of policy certainty.

> “Any uncertainty is the enemy of a free market.

Other drivers behind shifting perceptions of Alberta's power market include (listed alphabetically):

- A desire for regional diversification
- Clean Electricity Regulations
- Concern about oversupply
- Delays in regulatory processes
- Growth in share of intermittent renewables
- Pause on approvals for renewable energy generation projects
- Uncertain long-term carbon prices
- Uncertain treatment of natural gas generation beyond 2035
- Volatile power prices

**Shifting market outlook**

**Nearly all participants reported that their outlook for the Alberta power market had changed significantly in the past five years.** A small subset of the participant group said their outlook was unchanged. Of the participants that identified a shift in market outlook, most said their outlook today had deteriorated from five years ago. Longer regulatory approval processes and conflicting approaches to renewable power development were identified as the main drivers of this shift in outlook.

A few participants said they were now more likely to invest in renewables and less likely to invest in thermal generation, and others were uncertain. The participants who were most uncertain about their outlook for Alberta's power market are industrial consumers of electricity. These participants did note that they were now more likely to invest in non-emitting self-generation to support their corporate net-zero goals and ensure cost certainty.

**Regional comparison**

Participants were asked to compare Alberta with competing and neighbouring jurisdictions when it comes to the attractiveness of the power market.

Five (5) of the participants are geographically constrained to Alberta due to proximity to company assets that require electricity (i.e., cogeneration). The comments of these participants have been separated from the other nine (9) participants due to this geographic constraint.

Of these participants, most indicated that Alberta's power market has more regulatory and cost uncertainty than competing jurisdictions. Additionally, some of these participants indicated that Alberta's volatile electricity prices and high transmission costs have forced them to reduce their exposure to Alberta's power market and pursue business opportunities in other jurisdictions with reliable, affordable, and non-emitting power such as British Columbia. All of these respondents indicated that transmission costs were a greater concern in Alberta than in competing jurisdictions.

> “There is no way that this market can continue to be competitive for industrial production.

Of the remaining nine (9) participants who are not also industrial consumers of electricity (i.e., are exclusively in the business of power generation), most indicated that they were increasing their focus on jurisdictions outside of Alberta because of recent changes to their market outlook. Revenue certainty in other jurisdictions was listed as the primary driver behind this desire to invest elsewhere. Some of these participants indicated that they were exploring investment opportunities outside Alberta for the first time in 2023.

> “Alberta has always been a priority market for us. But for the first time in 2023, we started to evaluate other jurisdictions that had become relatively more attractive.

One developer expressed the view that attractive opportunities for renewable power development existed across Canada, including in Alberta.

A few participants—all of whom are developers of small, dispatchable generation—indicated that Alberta remained the most attractive jurisdiction for their projects. Alberta's deregulated market was viewed favourably by these participants, who view the deregulated market as a key driver for investment from smaller firms.

> “From an investment perspective, no, our outlook hasn't changed. It's a good place to do business.

Developers of renewable energy indicated that Saskatchewan, Ontario, Quebec, Nova Scotia, and New Brunswick were becoming attractive destinations for investment that would compete with Alberta to attract investment from renewable energy companies. Participants indicated that Alberta was previously the most preferable—or only—jurisdiction for developers, but recent procurements for non-emitting power in other jurisdictions would prevent Alberta from being the "most investible market in Canada" going forward. Participants indicated this effect would be exacerbated by the fact that Alberta became a relatively less attractive destination for renewable energy investment when it implemented a pause on project approvals.

Several of the globally diversified companies indicated that the power industry was becoming increasingly global with jurisdictions across the world competing to attract investment. Participants listed cost certainty, regulatory certainty, as well as favourable investment and production incentives as key drivers pulling investment outside of Alberta. Participants also expressed concerns over recent policy uncertainty in Alberta that made it relatively less attractive when compared with other jurisdictions. A small subset of the generator group indicated that other jurisdictions, particularly the United States, are focused on incenting investment in new generation, but Canada is more focused on punitive measures.

### INDIGENOUS MARKET PARTICIPANTS

#### Investibility today

Both participants expressed interest in further investment in Alberta's power market, particularly in renewables. Both expressed concern about the uncertainty caused by the recent pause on approvals for renewable projects. One was concerned that the pause on renewables would reduce the number of opportunities for Indigenous participation. The other pointed out that the delay in approving projects made cash flow calculation more difficult and could cause providers of capital to reconsider investment in Alberta-based projects, with negative economic consequences for Indigenous partners.

> “We're doing things like power forecasting out and now having to relook at power forecasting out because of [the pause on approving renewable energy projects] which is actually delaying projects that are already in process.
>
> So, I think it is very uncertain right now and I can tell you that that capital source we talk to does not like uncertainty...
>
> When I translate that back to Indigenous communities, increased risk comes with an increased [interest] rate. When they're financing at that rate it comes to decreased cash flows to the communities.

#### Regional comparison

Unlike some of the other participants, the jurisdictions of interest to the Indigenous groups were limited to within Canada. Both participants pointed to a disparity of existing structures for incorporating Indigenous participation across and within Canada. British Columbia was identified as having a good model for constructive engagement.

#### Shifting market outlook

Both participants indicated that their market outlook had deteriorated in recent years. The quality of engagement with the provincial government had shifted with a change in leadership and the resulting shift in priorities. Both mentioned being frustrated with the pause on renewables and with the effect of the conflicting federal and provincial goals on the outlook for investment. One also mentioned a deteriorating level of co-operation on issues such as abandoned wells and high power prices in the province.

### SUMMARY

**Uncertainty surrounding the outlook for renewable energy development, the perception of competing policy objectives between government bodies and concern about the ability to earn returns on legacy investments were all identified as sources of risk to future investment decisions.** All respondents were agreed that the power market in Alberta had at one time been an attractive place to operate. Positive features identified across the participant groups included the underlying economic growth in the province, link to the energy industry and the participation of the private sector. However, that same link to energy prices and lack of a government-sponsored counterparty were also seen as sources of volatility and uncertainty that increased the risk to investors in the market.

There was also a general consensus that the Alberta power market today was less attractive than it had been historically. The implications of this increase in perceived market risk are considerable. In some cases, the risk is seen as adding to the cost of capital of investing in projects in Alberta, making it more expensive to build in Alberta compared with other provinces or with jurisdictions outside Canada. In other cases, participants are increasingly looking outside Alberta for investment opportunities, some for the first time.

## SPECIFIC FEATURES OF THE POWER MARKET

Capital market participants were asked to offer unprompted comments on specific elements of the Alberta power market. Not every participant provided an opinion on every topic, but the quality and conviction of the responses was high.

### REVENUE CERTAINTY

#### Investors

Investors agreed that revenue certainty was important. Nearly all of the participants who offered an opinion said that the market did not offer a satisfactory level of revenue certainty. Several cited higher risk to production volumes in Alberta due to the nature of merchant contracts. A few said their investment horizon was limited by the term of contractually supported cash flow, which was five to seven years, and that they would not invest in projects beyond the term of the contract. Others cited the volatility of the power price in Alberta as being negative for revenue certainty.

> “You do the best you can, appreciating that there's uncertainty on both supply and demand. Even when you get that right, big numbers of megawatt

hours consumed in the year, that doesn't tell you everything about prices because prices go up and down an hour by hour. Different hours that have very different prices.

**Industry analysts**

This group also considered revenue certainty to be an important element for investment. Many respondents mentioned that revenue certainty was low and attributed that low certainty to:

- The merchant power market
- Volatility of power prices
- The expectation that power prices will decline in the near term
- The influence of the Clean Electricity Regulations on corporate PPAs

A small subset of the participant group said that revenue certainty is unlikely to improve as companies will need new production to meet Scope 2 emissions guidelines despite the fact that most revenue generation is from existing assets. Others said that market fundamentals are reasonable for a merchant market. Anticipating the next question, participants pointed out that investors required a higher return for the lower visibility on revenues.

“I think it's always been that view that if you're making a good part of your return from the merchant market, you need to earn a higher return.

## INVESTMENT HURDLE RATES

**Investors**

A definition of "hurdle rate" is available in the Glossary on page 23 of this report. Most participants said that they required higher spreads to compensate for higher perceived risk of merchant power contracts in Alberta compared with utilities in other jurisdictions. A few also mentioned that renewable projects, being of smaller size than large, baseload projects, would be funded with smaller and less liquid instruments. Investors would have additional requirement for higher spreads to compensate for lower liquidity of smaller issues. A few also mentioned that spreads would change with the economic cycle and offer opportunities to add value through trading.

**Industry analysts**

All respondents who answered this question said hurdle rates need to be high. The most common factors that require hurdle rates to be high include (sorted by frequency of mention):

- Merchant market exposure
- Rising interest rates
- Policy uncertainty

A small subset of the respondents recommended that investors avoid making any investments until the new market rules are available.

## AVAILABILITY OF PROJECT FINANCING

**Investors**

There was no clear consensus among investors on this issue. A few felt that it would be difficult to obtain financing for generation projects. An equal proportion mentioned that there would be no trouble in sourcing capital at the right price. A small subset of the participants characterized availability as "middle of the pack."

**Industry analysts**

The industry analysts were more constructive on the topic of the availability of project financing with the consensus that capital was available at the right terms and price, even if that price was high. A few respondents said that access to capital is still favourable at the right price, an equal proportion said that capital is available for quality developers with good track records and contracted projects, despite the increase in interest rates, and some respondents went on to say that there is an increasing acceptance of a certain level of market risk, but other investors are more conservative and participate less. A small subset of respondents said financing is there but accessing it is challenging.

“So, there is a set group of lenders that have gotten their heads around [merchant power risk]. And there's others that don't and are more conservative and not willing to deal with any merchant risk at all. And participate far less in [Alberta's power] market.

## POLICY FRAMEWORK GOVERNING POWER IN ALBERTA

**Investors**

A majority of participants raised concerns about the current state of uncertainty in the policy framework governing power in Alberta. The policy framework is seen as detrimental to the investment climate in the province as investors may move to the sidelines or invest elsewhere until policy clarity is available. Most investors raised concerns about the policy of prioritizing investment in renewable power generation. Concerns included:

- Increasing power price volatility from greater reliance on renewables
- Renewable tax credits incentivizing uneconomic projects
- Overbuilding capacity leading to lower returns in the market
- Risk of grid instability from increasing reliance on non-dispatchable assets

“This is a constitutional battle between the province and the federal government. It's not clear how it gets resolved.... And the power generation companies are caught in the crossfire. And they're being demanded by the federal government to retire assets that are still serviceable and still needed for grid stability.

Several investors pointed out that Alberta's policy framework has been unpredictable in the past because of multiple reviews. A few participants also suggested that the existing framework benefits incumbent operators by discouraging new investment. An equal number of participants characterized the existing policy framework favourably as a true market in contrast to the oligopoly or monopoly framework in other provinces. A small subset of the participants raised the issue of abrogation of contracts in a past review and expressed concern that something similar could happen again.

**Industry analysts**

All participants agreed that the current uncertainty was making investment decisions harder than in the past. Like the investor participants, the analysts were quick to recall past regulatory and policy reviews and the impact of changing political regimes on the expectation of investment returns.

> “I don’t mind if different governments come in and have different views of how to subsidize the next megawatt. But if you start making policies that hurt my existing assets, before I have the chance to actually recover return on and of the capital, that’s difficult.

Respondents expressed frustration about the way changes have been communicated, including the announcement of the potential for a Crown corporation, adding to the already uncertain investment climate. A few respondents were critical of the province and accused them of political posturing, citing the need for a unified front among Federal and Provincial governments. A smaller proportion said they understood the need for market redesign and that a Crown corporation might be appropriate.

### BARRIERS TO ENTRY FOR SMALLER COMPANIES

**Investors**

All participants who provided a response agreed on the existence of barriers to entry for smaller companies. Some suggested this was due to the market dominance of a small number of large companies in the province. An equal proportion suggested that smaller companies lacked the financial and human resources necessary to raise capital, negotiate contracts and participate in a competitive bidding process.

**Industry analysts**

A strong majority of participants agreed that barriers to entry are significant for smaller companies. Half of these participants also indicated that this held true in other markets as well. Examples of barriers were access to capital, and bargaining power in securing contract agreements. Several participants suggested that a successful business model for smaller players would be to bring a project to a late stage of development and sell it to a larger company. A smaller number of participants took a different view and said that small companies can easily enter the market and that barriers to entry for renewables are minimal.

**Indigenous market participants**

Both participants agreed that barriers to participation in power projects exist for Indigenous groups. One such barrier was the occupied market share of existing power generators such as Capital Power and TransAlta, including the pending acquisition of Heartland (which makes it even harder for smaller groups to break into the market). Another barrier was the lack of standardized structure for incorporating the participation of Indigenous market participants. The participants encouraged the development of standards across government bodies that would remove the barriers to Indigenous participation. Suggestions for standards included:

- Formal recognition of the value of Indigenous contributions
- A common definition of Indigenous across federal and provincial governments
- Incentives to project developers to incorporate Indigenous contributions
- A financing structure to facilitate economic participation
- Compliance verification of fulfillment of commitments

### SUMMARY

**Participants had very little conviction of how to incorporate their concerns about the current state of policy uncertainty into an investment calculation.** In their comments about specific features of the Alberta power market, capital markets participants were aligned on the importance of revenue certainty. They were able to identify several variables that contribute to the revenue certainty of a project and how those variables could be incorporated in an investment valuation. Similarly, with hurdle rates and access to project financing, participants differed in their appraisals of the challenges created by rising hurdle rates and availability of project financing, but they were able to articulate ways to incorporate these challenges in a valuation exercise. This was not the case with the policy framework governing investment in the province. While respecting the intention of a market based on private sector investment, participants were mindful of the negative economic consequences for historical investments of policy shifts in the past.

## MARKET DESIGN

**All participants were asked to provide comments on the effectiveness and adequacy of Alberta’s existing market regime, the energy-only model.** Participants were also asked to comment on the effectiveness of introducing elements of a capacity market or integrated system planning as means to achieve concurrent goals of emissions reduction, affordability, and reliability. Participants were also asked to identify their preferred market design to incent investment in the province. Some participants also used this opportunity to comment on the potential introduction of a provincial Crown corporation.

## ENERGY-ONLY MARKET

### Investors

All participants expressed a preference for cash flow certainty and regulatory stability but there was a great deal of concern about how implementation of any market design changes could have negative consequences for confidence in the market. The negative impact of past policy changes on market economics was a recurring theme.

> “You know, the [province] was going to add a capacity market; the government canceled that, and now we're back into some kind of uncertainty.

Most investors suggested that investible contracts could be structured within the energy-only market.

Further, most of these investors also expressed concern that changes in market design had been harmful to operators in the past and that the mismatch between contract terms and election cycles created added risk to investors.

> “You always are going to have trouble when you've got an AESO that needs to make 20/30-year recommendation on how the power market's going to work in a government who is thinking about getting elected in the next five years.

Several investors suggested that only a PPA or contract for differences would be acceptable investment options in an energy-only market. However, an equal number of investors believed that the energy-only market already offered appropriate price signals for investment decision-making. A few investors expressed caution about increasing reliance on renewable energy in an energy-only market due to the price volatility that comes with a heavy concentration of non-dispatchable power, and the economic distortions caused by renewable energy credits. The remaining respondents said the issue required more study.

### Industry analysts

When asked what the current level of support is for the energy-only market, participants said support for the energy-only market was high but there was disagreement over what modifications could be implemented without negative consequences. **There was support for the price signalling benefits of an energy-only market to investors, and resistance to changing a model now that market participants know how to work within it.** A few suggested that investors would resist adding elements of a capacity market due to the risk of overcapacity.

A few participants were less supportive of the energy-only market, suggesting the market was currently not suitable for attracting investment. A small subset of the participant group suggested that the energy-only market is becoming a “monopoly-light” that keeps prices artificially high. The pending acquisition of Heartland Generation by TransAlta Corporation was offered as an example.

> “There's high expectation that there is going to be some market redesign. In Alberta, the reason for that is that the energy-only market was put in time in a place where other factors didn't matter. Emissions were not part of the consideration, location, time of use, those sorts of things were not a consideration.

### Power generators

At a high level, there was a general agreement amongst the participants that the existing market framework is set up to deliver on concurrent goals of emissions reduction and affordability. However, most participants agreed that minor interventions to support system reliability could be warranted, which includes support from participants in each of the three technology groupings (renewables-only, thermal-only, and diversified).

> “We need an energy-only market that has the provision for ancillary services to be provided.

**Despite the many and diverse comments from participants on the various shortcomings of the energy-only model, it remained the most supported model to incent investment,** with near unanimous support. The energy-only model was the most preferred option for nearly all of the participants.

> “I believe the energy-only model can work. I think high prices are bringing in new participants to the market and that will bring prices down. So, I think it's working as it should.

The remaining participant, who is also an industrial consumer of electricity, expressed support for integrated system planning. This participant suggested that this model would result in less volatility in the power price, thereby facilitating improved decision-making regarding the siting of generation and transmission to minimize total delivered cost.

## CAPACITY MARKET

### Investors

**Investors were supportive of cash flow certainty and policy stability but did not necessarily see a capacity market as the means to achieve this outcome.** Several investors expressed indifference between energy-only and capacity market and were comfortable with the possibility that investible contracts could be created in either market design. An equal number of investors were concerned about the risk of overbuilding in a capacity market, particularly when compounded with the misleading economic effects of Renewable Energy Credits. The potential combination of a capacity market with Renewable Energy Credits would not provide appropriate price signals for investment decision making.

> Make sure it's not done in a way that opens a floodgate of subsidized capital that disadvantages the incumbent players who have earned very low returns on the capital they have invested in the market.

**Industry analysts**

The analysts were asked for their view of **investor** support for a capacity market rather than their own opinions. Most respondents said support was not high which aligns with the feedback from investor participants. There was concern about how such a change would be implemented and skepticism that a capacity market could meaningfully change the risk-reward characteristics of the market in comparison with the existing market design. A small subset of the participant group suggested that a change to a capacity market would cause investor sentiment to improve.

> Let the market function as is and don't interfere with the structure because once you set the rules of engagement, you should just let the firms invest based on what they know of the rule of engagement. But continue to change the dynamic of market -- it's just not fair for companies that are potentially putting billions of dollars to work.

**Power generators**

**Nearly all participants in this group did not view introducing elements of a capacity market or integrated system planning favourably.** Participants who were opposed to introducing elements of a capacity market or integrated system planning argued that substantial market design changes cannot be completed quickly enough to address the challenges that proponents suggest it could solve, such as ensuring affordability.

Several participants indicated that they expect new capacity additions of renewable and thermal generation in 2024 and 2025 to drive down prices, which demonstrates the "healthy functioning of Alberta's power market," where the high prices of recent years have signalled investors to invest in new generation.

> Capacity markets are highly complicated. We just don't feel that path is worthwhile for the invested time.

**INTEGRATED SYSTEM PLANNING**

**Investors**

This model was not very well understood by investors and most declined to offer an opinion. All investors that contributed answers believed that some amount of system planning is necessary in a market where assets are aging and being replaced. Some of these participants also suggested that a model similar to that of Ontario would be beneficial.

**Industry analysts**

Support from industry analysts was mixed for a market design with a greater role for integrated system planning. Most were unclear about how such a system would be implemented. Most participants were not supportive of the integrated planning option for the disruption in price signalling, although a few suggested that this type of structure might be appropriate to solve specific problems such as building assets to support grid stability or sunsetting legacy assets. A few participants cited Ontario as an example of an ineffective pricing system.

**SUGGESTED POLICY CHANGES IN SUPPORT OF A MORE CONSTRUCTIVE INVESTMENT ENVIRONMENT**

**Investors**

There was no clear consensus among the investment community on suggested policy changes to promote investment in Alberta's power market. A few investors suggested the regulator should provide clearer guidance and transparency about the path forward. A smaller number of investors was concerned about the negative impacts of too much investment in renewable power. A few investors also suggested the best course for regulators would be to avoid creating any further uncertainty as current and past regulatory changes have hurt investors. Other participants were of the view that there should be increased investment in renewable power or said there was nothing that policymakers could do to improve investor confidence.

**Industry analysts**

Similarly, there was **little consensus on policy changes among industry analysts.** Some respondents said less government intervention, but a subset of this group added that if interference was limited to support for grid reliability, then that would be encouraged. Several respondents advised against any measures that added to market uncertainty including intervention in the energy-only market or reduced visibility on carbon prices. A few respondents recommended measures to add predictability, including carbon price commitments. A small subset of the analyst community recommended incentives/tax credits for specific types of investments such as batteries or nuclear. Another small subset said they were unsure because the market seemed to be working prior to the review but recognized that market needs are changing and it's good the government is consulting because "we can't just experiment."

> So I think I'll start with saying that if you don't need to intervene, that itself is good policy...

**Power generators**

A majority of the participants who indicated the energy-only model was their most preferred model to incent investment also indicated that they would support the introduction of new market products for reliability services. They acknowledged that the energy-only model does not currently provide meaningful incentives for investors to support system reliability. Participants urged that these services should be procured competitively to maintain the fundamental principle of competition within Alberta's power market.

> “In the energy-only market, we assume that all the services that aren't energy will magically appear with the energy megawatt hours, but that isn't the case. We need to pay for those services.

Several of these also respondents indicated that a functioning energy storage tariff could also provide a means to ensuring reliability within the existing energy-only construct. A small subset of the generator group suggested that market reforms to support reliability might make sense once the draft federal Clean Electricity Regulations have been finalized, but to make market reforms before the final form of the regulations is known would not make sense.

A few participants indicated that new measures to strengthen offer control limits would support a more competitive marketplace that minimizes aggressive offer behaviour from Alberta's largest power companies.

> “Alberta isn't a competitive marketplace, it's an oligopoly.

### APPROPRIATE CONDITIONS FOR LARGE-SCALE DISPATCHABLE FACILITIES

#### Investors

When asked what conditions would provide appropriate incentives for large-scale dispatchable facilities, investors were unanimous in the requirement for cash flow certainty in some form. Suggestions included:

- Demand guarantees
- Capacity payments
- Fixed prices
- Long-term contracts
- Debt service reserve
- Risk mitigation at the construction phase

#### Industry analysts

The industry analysts provided similar responses to the investors on this issue with emphasis on the requirement that predictability of return on investment should survive any changes in government. A few analysts made specific reference to the historical treatment of coal-fired generation.

> “I want to know that I can run my unit for 15, 20 years to make a return of and all my capital. If there was a concern about the useful life or how long that unit can be in the market, then that would be a big deterrent.

Recommendations included:

- Long-term/life-of asset contracts
- Government/regulatory support
- Clarity on carbon pricing

### POWER PURCHASE AGREEMENTS WITHIN THE ENERGY-ONLY MARKET

Most participants did not have strong opinions on the topic and those that did, indicated that agreements of this type should be reviewed on a case-by-case basis. One offered that there may be cases where such power purchase agreements would be beneficial but cautioned that they were a “blunt instrument” that could do more harm than good in the market if improperly implemented. Another respondent was also cautious on implementation and mentioned variables such as inflation protection for added certainty.

#### Discussion of a provincial Crown corporation

A strong majority of participants who were asked to provide comments on the impact of introducing a provincial Crown corporation to purchase, build, and operate natural gas assets said such a move would have negative consequences for existing investors in the marketplace and disincentivize future investment.

> “A provincial Crown corporation would be entirely destructive to investment in Alberta.

A small subset of the participant group viewed the prospect of introducing a provincial Crown corporation positively, suggesting that current circumstances warrant intervention from the government.

### SUMMARY

**Participants from all groups were broadly supportive of the energy-only market.** They view energy-only as a fair and theoretically attractive feature of the Alberta market which should support competition and provide incentives for new construction. Energy-only was identified, particularly by power generators, as the preferred model for achieving the objectives of affordability and emissions reduction in the market. Participants recognized that the concurrent objective of reliability would require special arrangements but were generally confident that those arrangements could be achieved through competitive procurements for reliability services within the energy-only model. Similarly, members of the investment community believed that their concerns about revenue certainty could be addressed within the current market design.

**Participants were generally unwilling to recommend structural changes in market design.** This was particularly evident among power generators but also true of capital market participants. The responses of all groups made it clear they would prefer to work within the existing market structure both because they considered it to be superior to other structures and because they had no appetite for the disruption that would result from a new market structure and the long-term risks to the market from a poorly designed or poorly implemented change.

## POLICY ISSUES FOR CAPITAL MARKETS PARTICIPANTS

Capital markets participants were asked for unprompted opinions on specific policy elements to gauge whether these items had meaningful impacts on the investibility of the market.

### OUT-OF-MARKET AGREEMENTS FOR RENEWABLES

**Investors**

This issue was not well understood and most declined to comment. The few investors who did provide comments were not in favour due to the economic distortions to the market created by renewable energy credits.

**Industry analysts**

When asked about out-of-market agreements or credits for renewables, only a few participants provided a response. **Most respondents said out-of-market agreements are not necessary today because the market provides sufficient incentives for investment.** They suggested exceptions were possible to incent particular types of essential assets such as energy storage that might not be constructed by relying on market conditions alone. The remaining subset of the participant group said that these agreements are constructive as the right mix of policies and subsidies offer support for investment in the province.

### UNCERTAINTY OF THE FEDERAL APPROACH TO GAS-FIRED GENERATION

**Investors**

A strong majority believed that the uncertainty was having a negative effect on the power market. A smaller number believed that the focus away from gas-fired generation was misguided and would leave the power market in deficit. Others suggested that the change from 2050 to 2035 had negative consequences for the economic life of assets in the market and that such decisions should be left to the province. The remaining participants said the topic could not be considered in isolation.

> “The federal government wants Alberta to add renewable resources which are non-dispatchable and don’t have any grid support characteristics like voltage and frequency support and stability, synchronicities, spinning reserve. All these ancillary services that are critical to maintaining grid stability, renewables just don’t offer that.

**Industry analysts**

Many analysts pointed out that the Clean Electricity Regulations (CER) were not yet final and subject to change with the upcoming election cycle. Several respondents said the uncertainty is impacting investment, with some respondents saying that investors do not understand it and investment is sitting on the sidelines until the details are final. Fewer respondents said that CER can work with some modifications. A small subset of the analyst group indicated that they hope the CER can be relaxed. Another subset suggested that the CER present affordability concerns and that any shift to a lower carbon future should be done with a consideration of affordability.

Some analysts indicated they would require evidence of available returns on zero-emissions and carbon capture projects before making an investment decision. Further, they suggested that the time required for a first-of-a-kind project to gain regulatory approval, secure investment, complete construction, and measure investment returns before new projects are sanctioned will make it unrealistic to achieve a target decarbonization date of 2035.

> “Generally, we see two to three years of planning, permitting, circling, financing, and then three years of actually building. Round-trip, we’re talking six years to build facilities. If you’re building facilities that are first of a kind or novel in any way, instead of building them in parallel, you’ll want to see how one of them works.

### UNCERTAINTY OF THE PROVINCIAL APPROACH TO RENEWABLE GENERATION

**Investors**

Investors were divided on this issue with the only consensus around the assertion that the markets were surprised with the manner in which the pause was implemented.

> “this kind of, kind of pause in renewables really came at as a surprise. It wasn’t something I was expecting now…markets hate uncertainty.

Several investors believe that the pause on renewable energy development was appropriate. However, an equal proportion believed that Alberta needs to increase investment in renewables. A small subset of the investor group is concerned that the unexpected pause on renewable development adds to investor uncertainty.

**Industry analysts**

All of the analysts agreed that the uncertainty that resulted from the provincial pause on approvals for renewable energy projects was negative for the investment climate, there was no consensus on whether it was prudent or what would be achieved by it. A few respondents said that the motivations by the province were unclear, and they are waiting to see the outcome of the Inquiry. However, an equal number of analysts see the pause as important for grid reliability to put a framework around renewables and think about the asset impact on the grid. A subset of this group also suggested that the pause could have been implemented in a less abrupt manner. A small subset of the analyst group said that the provincial approach seems ideological and inconsistent with its approach to oil and gas development.

> you could have more certainty that you would have project success a few years ago, because there's fewer projects that you were competing with. Now, in totality, there's 43 gigawatts looking to be interconnected to the grid. So, your prospects of being successful are much lower.

### PERCEPTION OF DIFFERENT APPROACHES BETWEEN FEDERAL AND PROVINCIAL AUTHORITIES

#### Investors

All investors agreed that the uncertainty created by the conflicting approaches was a problem for all stakeholders. Sources of uncertainty cited by investors included:

- Mismatch of long-term investment horizons with short-term political cycles
- Concern about what actions one group might take to push back against another
- A shortage of necessary investments pending clarification of jurisdictional authority

Although there was agreement about the negative effects of conflicting policy objectives, there was less agreement about where decision-making authority should reside. Many investors believed that jurisdictional authority should reside with the province. Fewer investors believed that the federal approach was the correct one. The remaining investors believed that the federal government was within its authority to make national decarbonization commitments, but the implementation should be left to the provinces.

#### Industry analysts

Again, there was agreement from all participants that this discrepancy was having a negative impact on the investibility of the market.

> But it does create a disruption in the eyes of investors. Someone's deciding here what stock they want to buy, which company comes to market to raise equity, fund a growth ambition. If there is something that just seems more complicated than it needs to be, or a seed of doubt that keeps coming back up, that does a disservice to those companies.

There was less agreement on how to resolve this discrepancy. Many analysts questioned the economic justification for the behaviour of the province. However, several participants said that the federal program does not take provincial differences into account and went on to say that the federal government does not recognize the uniqueness of power and resources available for power by each province.

### SUMMARY

Participants had a range of views on the policy initiatives of the different government bodies. There was no consensus on which approach was valid or which body should have jurisdiction. There was agreement, however, that the reality of differing approaches added uncertainty to the investibility of the provincial power market. **The overwhelming response to uncertainty was delay.** Investors were willing to delay investment decisions pending regulatory clarity. Given the many years' lead time required for approval and construction of power projects, the prospect of delays could have implications for the achievement of all three objectives of reliability, affordability, and emissions reduction.

## INVESTMENT CONSIDERATIONS FOR POWER GENERATORS

Power generator participants were prompted to comment on any other policy, regulatory, or market considerations that have or might influence their outlook for investing in the Alberta power market.

At a high level, participants within both power-only and load groups shared the sentiment that many of the various policy proposals aimed at achieving concurrent goals of emissions reduction, affordability, and reliability could be tenable if they were perceived to be durable over time. However, participants were clear that, despite their concerns with certain aspects of the transmission regulations, permitting, carbon pricing, the Clean Electricity Regulations, or any other federal or provincial legislation, it was the inability to predictably model future policy environments that presented the most considerable impediment to investment. The perceived complexity of the regulatory and market dynamics in the Alberta power market presented a more significant barrier to investment than the content of any individual policy.

> I think the uncertainty that's going on right now has made everybody take a step back to say, hey, hold on a second, if I've got other options, I'm going to go pursue those.

Acknowledging the above, the participants in the study did provide specific comments on several policy, regulatory, or market considerations that influenced their outlook for investing in the Alberta power market. To categorize the responses, the participant groups have been separated into two groups: participants that are exclusively in the business of electricity generation (8 participants) and participants that are also industrial consumers of electricity (5 participants) in recognition of the fact that the policy interests would differ between the two groups.

#### Power-only (9 participants)

Participants in this group provided comments on the following considerations:

- **Carbon pricing**

  Regarding carbon pricing,

perspectives varied widely. A few developers of dispatchable gas generation indicated that carbon pricing negatively impacted their outlook for investing in Alberta. By contrast, developers of renewable generation indicated that carbon pricing had a positive impact on their market outlook.

> “ [the carbon price] will effect change and drive people to do things differently. It already is.

Several other participants indicated that current carbon pricing made them more likely to invest in renewable generation and less likely to invest in thermal generation. The remaining participants said that the impact of the carbon price was neutral.

▶ **Draft Clean Electricity Regulations**

Participants were generally aligned that the draft Clean Electricity Regulations (CER) were a disincentive to investment. Most participants indicated that they would be less likely to invest in thermal generation until the CER are finalized. A subset of this group also indicated that the CER increases uncertainty across technology types until it is finalized. The remaining participants indicated that the CER would not influence their investment decisions or that they were uncertain. Participants generally agreed that the uncertainty regarding the final form of the draft regulations was a greater concern than the regulations themselves, which were viewed as challenging, but tenable. Many participants indicated that they expected the final form of CER to be more flexible than the current draft regulations.

▶ **Provincial pause on approvals for renewables**

Regarding the pause on approvals for renewables, participants were divided. Several participants called for an immediate cancellation of the pause on project approvals. They were concerned with the lack of consultation in implementing the pause and concerned that the pause was a signal to investors that investment in renewables was not welcome. A smaller group of participants expressed support for the pause, suggesting the rapid growth of renewables warranted a pause. The remaining participants did not comment.

▶ **Investment tax credits (ITCs)**

Participants were divided in their views on tax credits for both renewables as well as carbon capture and storage. Many companies expressed support for a level playing field, with no investment tax credits for any form of generation or carbon abatement. However, several participants indicated that ITCs were required to attract capital to Alberta, particularly in competition with the Inflation Reduction Act in the United States. One company was ineligible for investment tax credits and did not comment.

▶ **Government de-risking for dispatchable and baseload generation**

Most participants expressed support for minimal or zero government intervention in the marketplace. Some of the participants expressed support—those participants were developers of small-scale (<25MW), dispatchable generation. A small subset of the participant group suggested that capital providers located in the province such as ATB Financial and the Alberta Investment Management Corporation should become more directly involved in providing debt financing on favourable terms to developers of baseload and dispatchable generation.

▶ **Policy certainty**

All participants agreed that policy uncertainty presented a serious impediment to their outlook for investing in Alberta. Whilst perspectives varied greatly on the causes of policy uncertainty, participants identified the following factors as contributing to policy uncertainty:

- Draft Clean Electricity Regulations
- Long-term carbon prices, or the existence of a carbon tax regime itself
- Combative provincial approach to federal environmental policy
- Discussion of potential market design changes
- Pause on approvals for renewable energy generation projects
- Long or complex decision- and rate-making processes at the Alberta Utilities Commission
- Transmission regulations

> “ As [generators] are trying to decide whether or not to work in Alberta, they don’t know what they are going to be investing into in the next several years because policy is under question and the market structure itself is under question.

**Load (5 participants)**

Participants in this group provided comments on the following considerations:

▶ **Cost of transmission**

Participants in this group generally agreed that the cost of transmission was their principal concern with Alberta’s power market. Most participants called for consideration of transmission costs to be more thoroughly integrated in proposals for new generation. These participants also called for the introduction of cost causation in provincial transmission regulations, suggesting that generators should be required to pay for at least a portion of any new transmission infrastructure. A subset of these participants also called for a requirement that new generation be built near Alberta’s existing transmission infrastructure.

- **Volatility**

  Participants expressed concerns about the impact of volatile electricity prices on their operating decisions. Several participants indicated they were more likely to invest in self-generation today than in recent years to achieve better cost certainty for power. A subset of this participant group indicated that the Alberta power market would not continue to be an attractive destination for load if volatility was not addressed.

> "I can't see how this continues to work for industrial load.

- **Emissions**

  Several participants indicated they were more likely to invest in self-generation today than in recent years to achieve corporate net-zero goals. The emissions intensity of Alberta's power supply was listed as the key driver for this change in outlook.

> "If we're going to import electricity, that comes with a carbon intensity. We can't credibly claim our products are net-zero if we include those emissions.

- **Consultation on regulation and market reforms**

  Nearly all participants indicated that consultations by the AUC, AESO, and the Government of Alberta on potential market design and policy changes need to be more inclusive of the perspectives of load. A few participants also indicated that they felt they had difficulties participating in consultations and were overwhelmed by the incumbent power generators who have greater financial resources as well as teams of regulatory and legal staff working to shift policy decisions in their favour.

**Scarcity pricing and economic withholding**

**None of the participants indicated that it would be beneficial to prevent companies from economically withholding at the risk of not being dispatched.** Participants who responded to this question indicated that scarcity pricing was a core tenet of the energy-only model that provides an incentive for risk-taking companies to invest in the power market. In removing the ability to economically withhold, participants suggested they would lose the potential to generate a return on capital and consequently the incentive to invest in new generation.

> "Scarcity pricing is a fundamental tenet of the energy-only market, you have to have it in some form.

**Barriers to entry for new entrants**

All generator participants were prompted to comment on any perceived barriers to entry in Alberta's power market. **Respondents were divided on the existence of barriers to entry, as well as on the potential causes.** Several participants indicated that there were no barriers to entry in Alberta's deregulated power market. Other identified barrier to entry for new entrants included (ranked by frequency of mention):

- The complexity of AUC application processes
- Policy uncertainty
- End-of-life treatment for gas-fired generation
- Lack of a functioning tariff for energy storage

### SUMMARY

**An enduring and reliable policy environment was seen as a more important contributor to effective market function in the future than any other single policy element.** The two different groups of market participants diverged on the aspects of the market that were most relevant to them. The power-only generators were deeply concerned about policy certainty and the impediments to investments caused by federal Clean Electricity Regulations still in draft form and the provincial pause on approvals for renewables. The load participants were concerned about the cost of transmission and the volatility of electricity prices. None of the participants advocated for increased government intervention as a means to resolve these concerns.

## INVESTMENT ANALYSIS AND VALUATION

To assist in understanding the perspectives of investors on the investibility of the market, the investor participants were asked to describe the inputs to their investment decision-making processes. Participants included providers of both debt and equity capital.  A description of both types of capital investment is available in the Glossary on page 23.

For both debt and equity investors, the investment process consists of an assessment of the timing, quality and reliability of cash flows associated with an investment. As such, many of the elements of the process were common to all participants including:

- Analysis of the revenue opportunity
- Calculation of the capital and operating costs associated with producing that revenue
- Assessment of the risks to the resulting cash flow calculation
- Comparison with similar competing investment opportunities
- Incorporating the analysis into a valuation model

### INVESTORS

Within the analysis, several investors identified specific inputs to the decision-making process:

- Almost all investors stated that they considered environmental or environmental, social and governance ("ESG") factors when making investment decisions.

A few of these investors also mentioned investment policies that prohibited certain types of investments in fossil fuels.

- The majority of investors mentioned looking at the policy and regulatory environment as part of the investment decision. This was important for considerations of:
  - Opportunity for revenue growth
  - Allowed return on equity ("ROE") and equity thickness
  - Risk of unfavourable changes in regulation or legislation
  - Potential for unprofitable operations or stranded assets
- The majority of investors mentioned the need for an appropriate mix of debt and equity in the financial structure that would properly reflect the risk to the cash flows of an investment.
- Most investors identified quality of management as a consideration.
- Most investors were limited to minimum credit quality standards as determined by a third party or internal risk rating.
- Most investors referred to adjustments to their risk models for the contractual nature of the cash flows including:
  - Whether the cash flows were contracted at all
  - Whether the contract incorporated inflation protection
  - Whether the term of the contract covered the term of the investment
  - Whether a contract was for baseload or peaking capacity
  - The form of the contract (Power Purchase Agreement ("PPA") or merchant power)
  - Quality of counterparty to the contract
- About half cited generating technology as a factor affecting such considerations as estimated asset life, capacity utilization, land lease term or future land remediation cost.

**INDUSTRY ANALYSTS**

The inputs to the valuation models were similar for the industry analysts.

- The majority said that revenue certainty as defined by the predictability of cash flows was very important for the evaluation of investments. The most frequently mentioned factors supporting revenue certainty included:
  - Cash flow visibility
  - Duration of contract
  - The form of the contract (PPA or merchant power)
  - Quality of counterparty to the contract
  - contractedness including bargaining power and the duration of PPAs
- A number of participants referred to the incorporation of operating costs and risks as defined by:
  - Asset quality
  - Asset efficiency
  - Dispatch frequency
  - Maintenance costs
  - Expected economic life of an asset
- Participants raised the issue of the quality and track record of management.
- About half the participants mentioned interest rates and the cost of capital.
- A few referred to financial risk as defined by the balance sheet and cash flow coverage of principal and interest payments.
- A few mentioned growth rates in demand for power in the market.

On the question of how these considerations would be adjusted to assess the value of an investment in renewable energy, investors and analysts had similar responses which are aggregated below:

- Most participants mentioned an increased consideration of the physical properties of a project.

> “[With] wind, you do have more of a definite life. The re-powering looks different than say re-powering a hydro project. So, as you're getting later in the life of a bond of a hydro project, your asset coverage is a fair bit higher than say for a wind project where there might be a land lease that's not indefinite.
>
> And your asset life is shorter overall. that equity cushion is shrinking as you're getting late into a wind project where it's not really the case with hydro.

- Many noted that the credit quality of renewables was lower due to shorter asset life, lower capacity factor, less predictability of non-dispatchable assets and higher risk of non-economic operations.
- Many also mentioned the larger role of government in the renewables market compared to non-renewable projects in the form of incentives and subsidies. Some suggested that renewables should receive a higher valuation due to cash flow support from government.

> “The valuation difference between thermal and renewables is that you would take a different approach to how you value post-2035 cash flows from a non-renewable project because you don't know whether or not that is going to be running and most investors will either place a very little value… on it running beyond 2035 until there is certainty.

## INVESTMENT JURISDICTION

### Investors

As part of the Inquiry into the investment decision-making process, participants were asked to identify characteristics of investment jurisdictions that they considered attractive.

**The most commonly cited characteristic of an attractive investment jurisdiction was policy stability,** followed by (in order of frequency of mention):

- Credible fossil fuel transition plans
- Availability of long-term contracts
- Contracts with investment-grade counterparties
- Supportive regulatory frameworks
- Attractive allowed returns on equity and equity thickness

Specific jurisdictions that were identified as attractive to investors were (in order of frequency of mention):

- British Columbia
- Ontario
- Florida
- Parts of the United States
- Quebec
- Nova Scotia
- Arizona
- California
- UK
- Other European countries
- Australia

Some investors reported that they had considered Alberta an attractive jurisdiction in the past but that this was no longer the case. When asked about recent capital deployments, several investors cited recent participation in a BC Hydro debt issue. **BC Hydro was offered as an example of an attractive investment with long-lived baseload hydro power generation assets and a low-risk counterparty in the form of a provincial Crown corporation.**

Some mentioned participating in the Capital Power issue following their recent US acquisition. Others invested in securities of Epcor, Northland Power, and NextEra Energy.

### Industry analysts

There was general consensus among participants about the characteristics of an attractive investment jurisdiction. The most commonly cited characteristic was breadth of opportunity, followed by supportive regulatory/political environment, demand growth, availability of long-term contracts, and active fossil fuel transition plans. There was general agreement that markets with uncertainty were difficult to invest in.

Specific jurisdictions that were identified as attractive included (in order of frequency of mention):

- Parts of the United States
- Canada
- Alberta
- Ontario
- Quebec
- Florida
- PJM
- Europe
- Asia

Interestingly, the investor preference for British Columbia as a jurisdiction was not reflected in the answers given by industry analysts.

> “ I'd say the US market is almost table stakes for most companies just because of the breadth of the opportunity there. But increasingly Canada, after going through what was probably a dry spell for new growth opportunity… We're now seeing an upswing both on the needed investments on the utility side… and on the power demand side from electrification trends, but also some more energy intensive industries that have been sort of stronger in the last couple of years.

## INVESTOR PERCEPTION

Industry analysts are in contact with hundreds of investors on a regular basis. As part of their interviews, analysts were asked to disclose what were the most significant issues for investors in connection with the Alberta power market. The most common response was that investors were increasingly concerned about policy uncertainty and the impact on asset life. Several mentioned a shift from a focus on growth to balance sheet quality. Several mentioned changes in the cost of capital and return on capital. A few participants suggested that investors were concerned about the effect of new supply on power prices. Others suggested that growth was the most important consideration.

## SUMMARY

**Any risks to cash flows in the form of uncertain operating profile, volatile input costs, uncontracted cash flows or excess financial leverage would result in a reduction in valuation through lower multiples or higher discount rates.** There was a good level of consensus among members of the investment community on the factors that contributed to the attractiveness of an investment. Predictability of cash flows and long asset lives would be rewarded with higher valuations.

> “ …and those that have policy uncertainty as well - those are difficult to invest in because of those uncertainties and we would require a higher discount rate.

The main difference between the two groups of market participants is that investors, unlike industry analysts, are often subject to the constraints of an investment policy that incorporates external credit quality and ESG parameters. Despite this difference, analysts did correctly identify the issues of primary concern to the investor population.

Investors and analysts were all able to identify jurisdictions in which attractive investment opportunities were available. Investors pointed to more opportunities within Canada whilst analysts were likely to identify jurisdictions both inside and outside Canada as desirable.

## SUPPLEMENTARY COMMENTS

Participants were offered the opportunity to provide additional comments. This was an open-ended question to allow participants to contribute content outside the framework of the interview. These comments are summarized below.

### Investor comments

- They could be a much more meaningful investor in Alberta if they could consider it on par with other jurisdictions such as British Columbia.
- Alberta has been thoughtful about managing its environmental impacts and is encouraged to continue.
- Policymakers must be mindful that investors have not earned returns in the last five to ten years that allowed them to recover the costs of invested assets in the market.

### Industry analyst comments

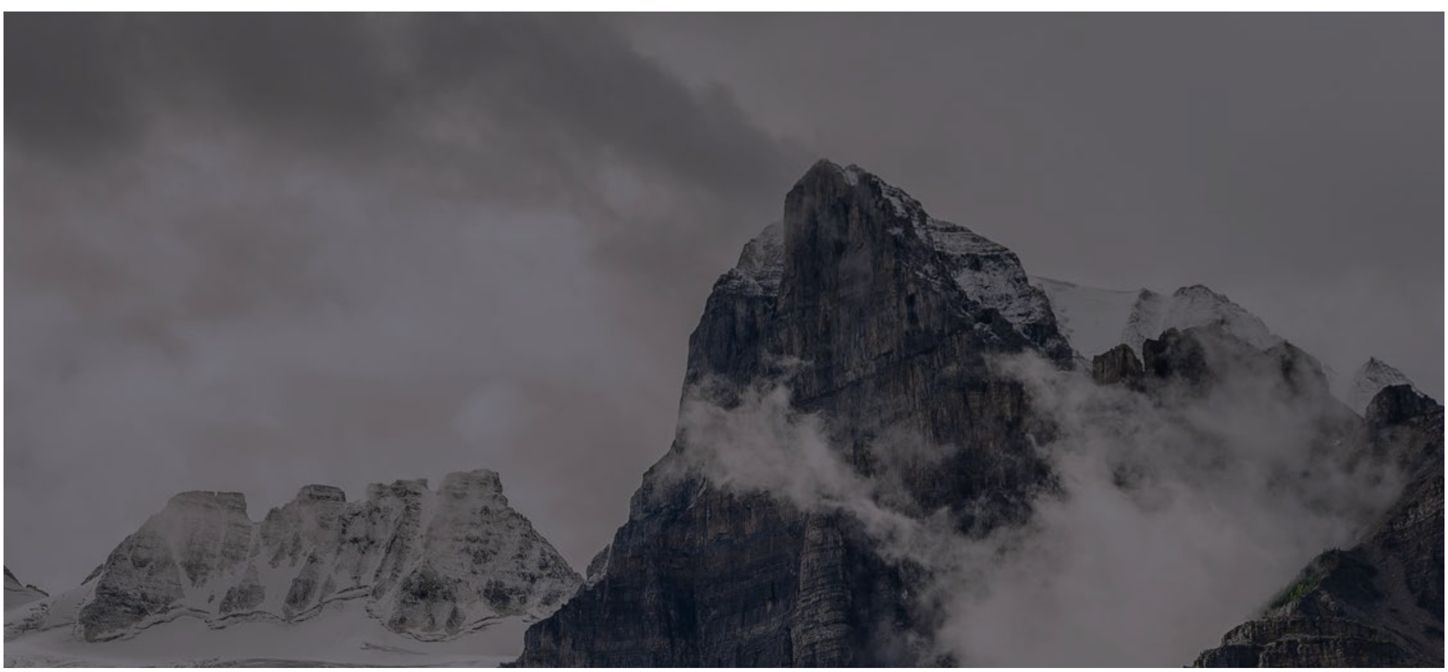
- There is a need for a more unified message between industry and government at the provincial level.
- There should be more emphasis on storage procurement if the market is to switch to non-dispatchable intermittent power.
- They hope that not much meaningfully changes.
- Certainty is important for investment and that the discrepancy in priorities between governments makes it hard to invest.

### Power generator comments

- The AUC was understaffed and required more resources to process applications expediently.
- The AUC must provide its honest advice to the government, rather than tell the government what it wants to hear.
- There should be a requirement for storage quotas for renewable projects, in line with the requirements for other infrastructure businesses in the province.
- The province needs to invest in intertie capacity to maintain reliability.
- Markets that move away from renewables, for whatever reason, have challenges attracting investment back to the region for several years.
- The industry needs to see the various inquiries and ambiguities facing Alberta's power market resolved as quickly as possible, and to have the results communicated back to industry as quickly as possible.
- It is important for the people of Alberta to understand that wind and solar power can reduce the cost of electricity in the province and offers as evidence the government-backed contracts that secured the Renewable Electricity Program.

### Indigenous market participants

> "Where do you identify opportunities for meaningful dialogue and actual partnership on these issues? It is really important to create space for us to be involved with government and with regulators because with these issues, if they are done well, they can have a long-term benefit for our communities. Let's work together."



# Conclusions

## Perspectives on the outlook for Alberta's power market are varied and changing rapidly.

Participants in this survey represent a diverse set of stakeholders in the market including providers of debt and equity capital, industry advisors, Indigenous market participants, and a subset of current and prospective generators of renewable and non-renewable electricity. Most participants agree that their outlook has changed substantially in recent years. Policy uncertainty is the primary driver of this shift in outlook.

For capital market participants, the perceived risk to returns on invested capital has led to market participants either withdrawing from the market or requiring significantly higher returns before committing capital to the market, increasing the cost of invested capital in the province compared with other jurisdictions. Similarly, policy uncertainty is leading several generators, particularly developers of thermal generation, to now be less likely to invest in Alberta in the short term. Other drivers were noted by participants, but no other factor was as frequently mentioned as policy uncertainty. **Many participants indicated that Alberta would continue to be an investible market in the long term if these policy concerns were to be resolved.**

Perspectives on the best solutions to support concurrent goals of emissions reduction, affordability, and reliability are equally diverse. However, there are areas of agreement where developers of electricity generation agree, including market design. **There was a general agreement amongst participants that the energy-only market is the most preferred market to incent investment in the province.** Introducing elements of other market designs, including capacity markets, integrated system planning, or a provincial Crown corporation was not viewed favourably by the respondents to the survey.

**Similarly, capital markets participants emphasized the need for predictability of cash flow to incent investment** and expressed confidence that structures to provide that predictability should be available within the energy-only market. Participants largely agreed that government participation in the power market would be destructive for investment from the private sector. Many made reference to the discrepancy between economic life of an asset and the duration of an election cycle as well as to the negative impacts to investment returns from past policy changes. For that reason, many market participants are less concerned with the shortcomings of the existing market design than with the potential adverse effects of implementing any change. **At a minimum, investors would be likely to pause investment in the market if not fully withdraw until sufficient long-term policy clarity is available.**

Participants largely agreed that the existing energy-only market is equipped to ensure an affordable and clean power system. However, many participants across respondent groups agreed that the introduction of new market products for reliability services could help support system reliability. These participants urged that these reliability services be procured competitively to uphold the foundational principle of competition within Alberta's power market.

**Policy uncertainty is currently the most significant impediment to investment in Alberta's electricity market.** This takes many forms, but the consensus amongst the participants of the survey was that the complicated, overlapping, and rapidly changing policy environment facing investors in the power market prevents them from modelling project revenues with any confidence and making sound investment decisions based on their modelling. Perspectives varied on who is most responsible for causing policy uncertainty. Participants suggested that the federal government, the provincial government, the Alberta Utilities Commission, and the Alberta Electric System Operator all play a role in contributing to the current situation. The consensus was clear that a more aligned approach would create a more constructive investment climate.

# Glossary

| | |
|---|---|
| **Clean Electricity Regulations** | The **Clean Electricity Regulations** are an element of the Government of Canada's actions to achieve a net-zero electrical grid by 2035. They were released in draft form in August 2023. |
| **Debt** | Providers of capital in the form of **debt** receive a return in the form of fixed principal and interest payments on the debt. Debt investors are primarily interested in the credit quality of an investment which is defined as the level of certainty of receiving the scheduled principal and interest payments. Debt investments are considered to be lower risk because project cash flows are allocated to debt payments ahead of any returns to equity investors. Because debt investments carry lower risk, they are generally a lower cost funding option than equity investments. |
| **Equity** | **Equity** investors receive a return on investment in two ways. They may receive dividend payments on their investment as well as an increase in the value of their investment on disposition. The value of an investment is a function of the cash flows to an entity after the payment of all required interest payments and taxes. If an investment is considered attractive, investors will pay a higher multiple of cash flows, resulting in a higher value for the investment. The goal of equity investing is to identify investments that are attractive today with the expectation of selling for a higher price in future. |
| **Equity thickness** | **Equity thickness** is the proportion of the capital base of a utility that consists of shareholder equity rather than debt. Other things being equal, investors prefer a thicker equity base over the alternative of taking on more debt. |
| **Hurdle rate** | The **hurdle rate** of an investment refers to the level of return on investment in a project that is necessary to entice investors to participate in that project. The reference for hurdle rate was yield spread over Government of Canada Bonds for debt investors and multiple of cash flow for equity investors. Investors and analysts all recognize the need for appropriate risk-adjusted returns or compensation for taking different types of investment risk. |
| **Investment-grade** | **Investment-grade** refers to the group of credit ratings that imply a low risk of default. Entities with investment-grade credit ratings are able to issue debt at a lower interest rate than others with weaker credit ratings. |
| **Investment tax credits** | **Investment tax credits** in Canada are incentives to business investment that allow investors to deduct a portion of their investment costs from their taxes. |
| **Net zero** | **Net zero** refers to a state in which all emissions of greenhouse gases into the atmosphere from human activities are offset by removal of greenhouse gases from other activities. |
| **Power purchase agreement** | A **power purchase agreement** is a long-term arrangement between the producer and consumer of power that specifies the volume and price of the purchased power. |
| **Renewable energy credits** | **Renewable energy credits** (also **renewable energy certificates**) are evidence of power generation from a renewable source. These can be purchased and sold to transfer the renewable aspect of energy generation from one owner to another. |
| **Return on equity** | **Return on equity** is a measure of the financial performance of an entity calculated by dividing the net income of an entity by the equity capital invested to produce that income. |
| **Scope 1, Scope 2 emissions** | **Scope 1** emissions refer to greenhouse gases that are generated from sources owned or controlled by an organization. **Scope 2** emissions are indirect emissions of greenhouse gas by an organization from purchased energy. Greenhouse gas emissions are a widely accepted reporting standard of the climate impact of an organization. |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