London Economics International LLC

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

www.londoneconomics.com

LONDON ECONOMICS

Agenda

LONDON ECONOMICS

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.*

LONDON ECONOMICS

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 On average, 54% of total bill	+	$23-$28 On average, 12% of total bill	+	$28-$92 On average, 21% of total bill	+	$22-$38 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		Transmission costs		Distribution costs		Other charges
• Based on the load-weighted average Pool Prices from LEI's POOLMod outputs, which differ by scenario	+	• 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	+	• 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)	+	• 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)

LONDON ECONOMICS

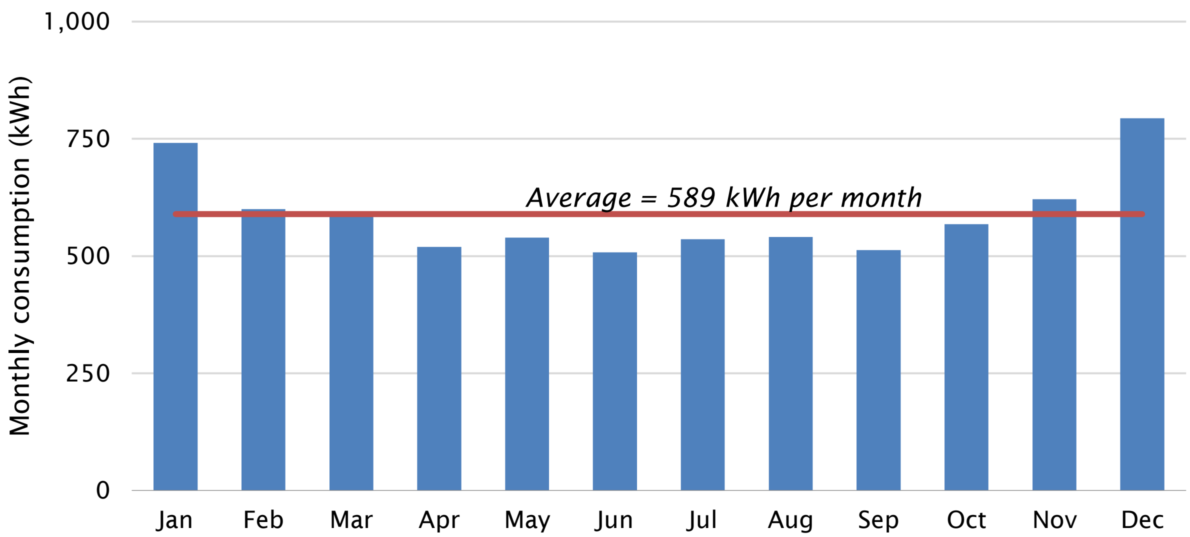
Agenda

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

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)

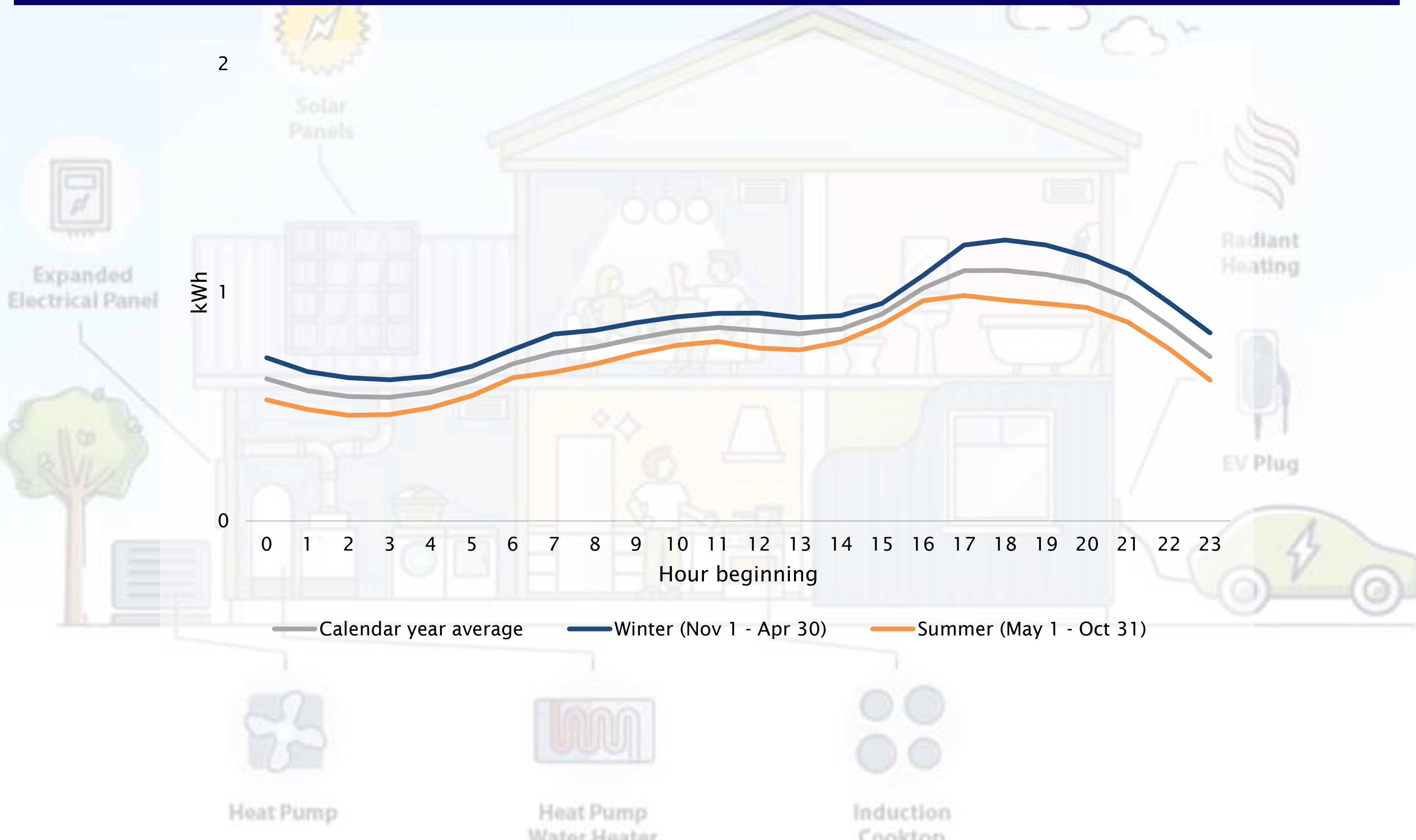


- **To test whether this assumption should change over time, LEI compared the growth in annual AIL energy (GWh) from AESO's preliminary 2024 LTO to provincial population growth estimates from the Government of Alberta**
  - Annual AIL energy grows at a CAGR of 1.1% over the 2024-2040 period according 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)

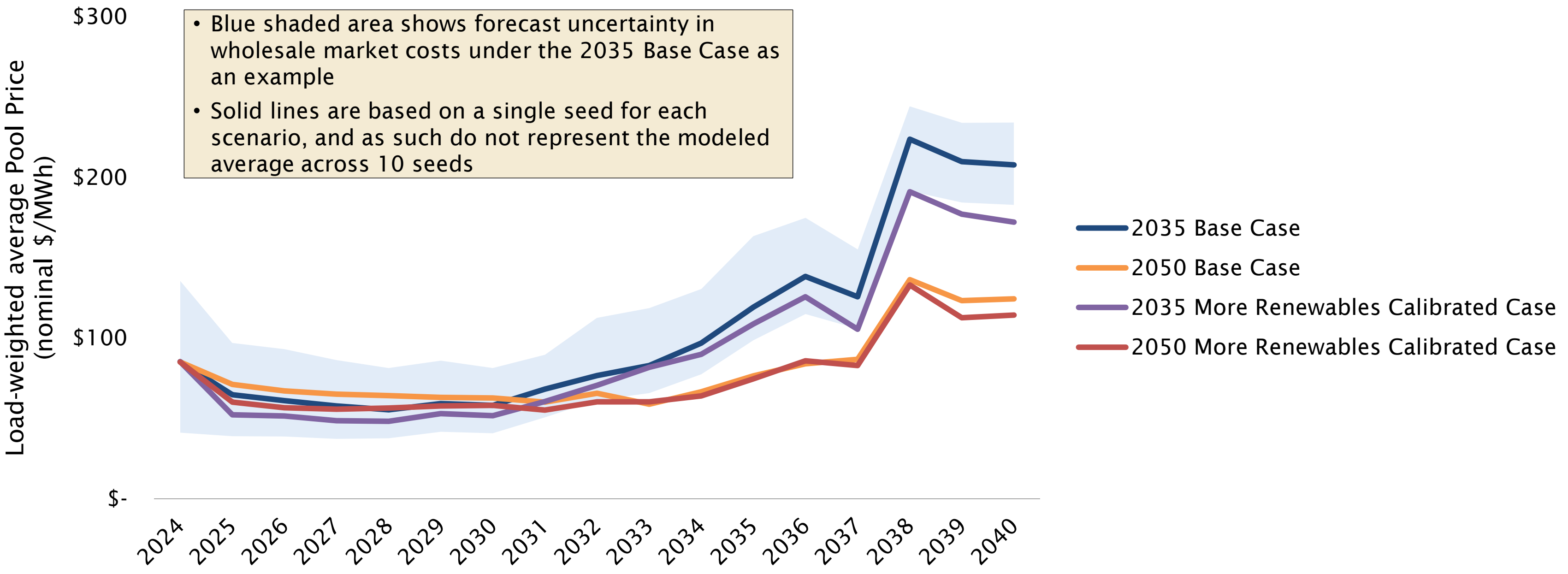


Note: Winter and summer months align with the AESO's seasonal definitions (*see for example* AESO. [2022 Annual Market Statistics.](#) March 2023).

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)

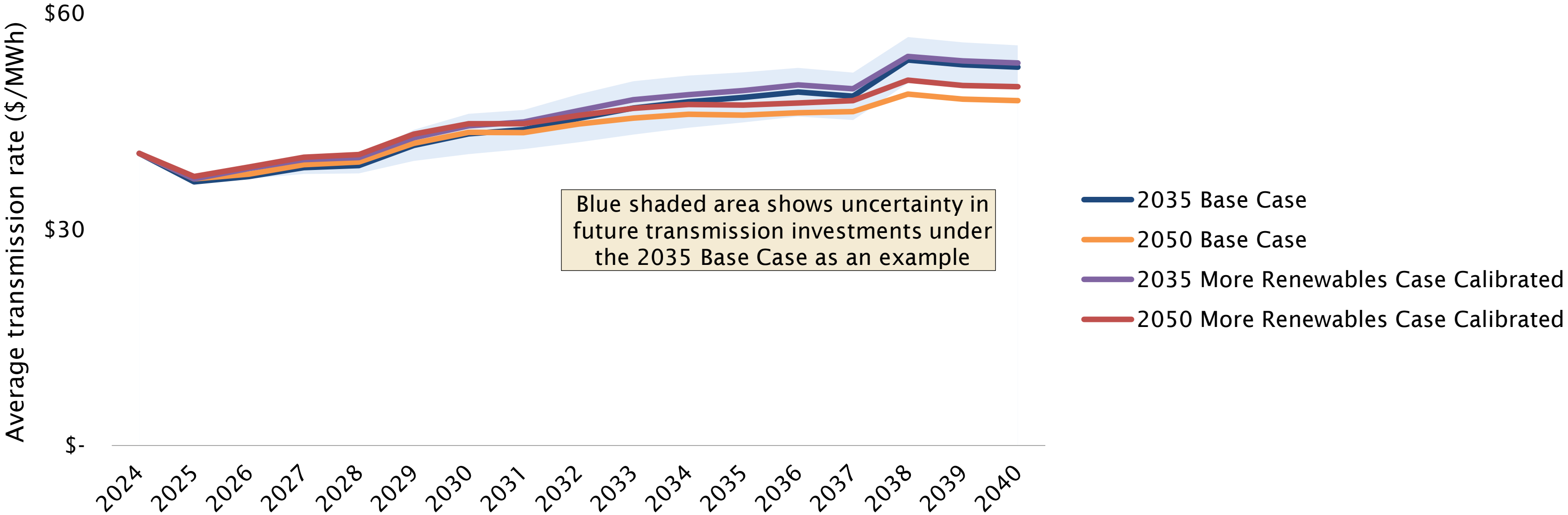


LE LONDON ECONOMICS

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.

LONDON ECONOMICS

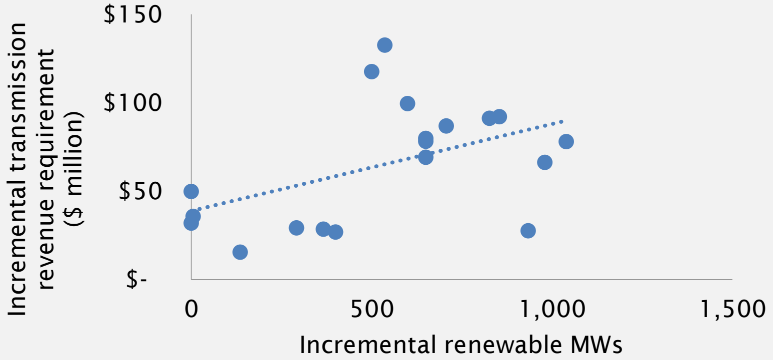
Transmission rates were estimated by leveraging AESO's Transmission Rate Projection model to incorporate several transmission cost components

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:



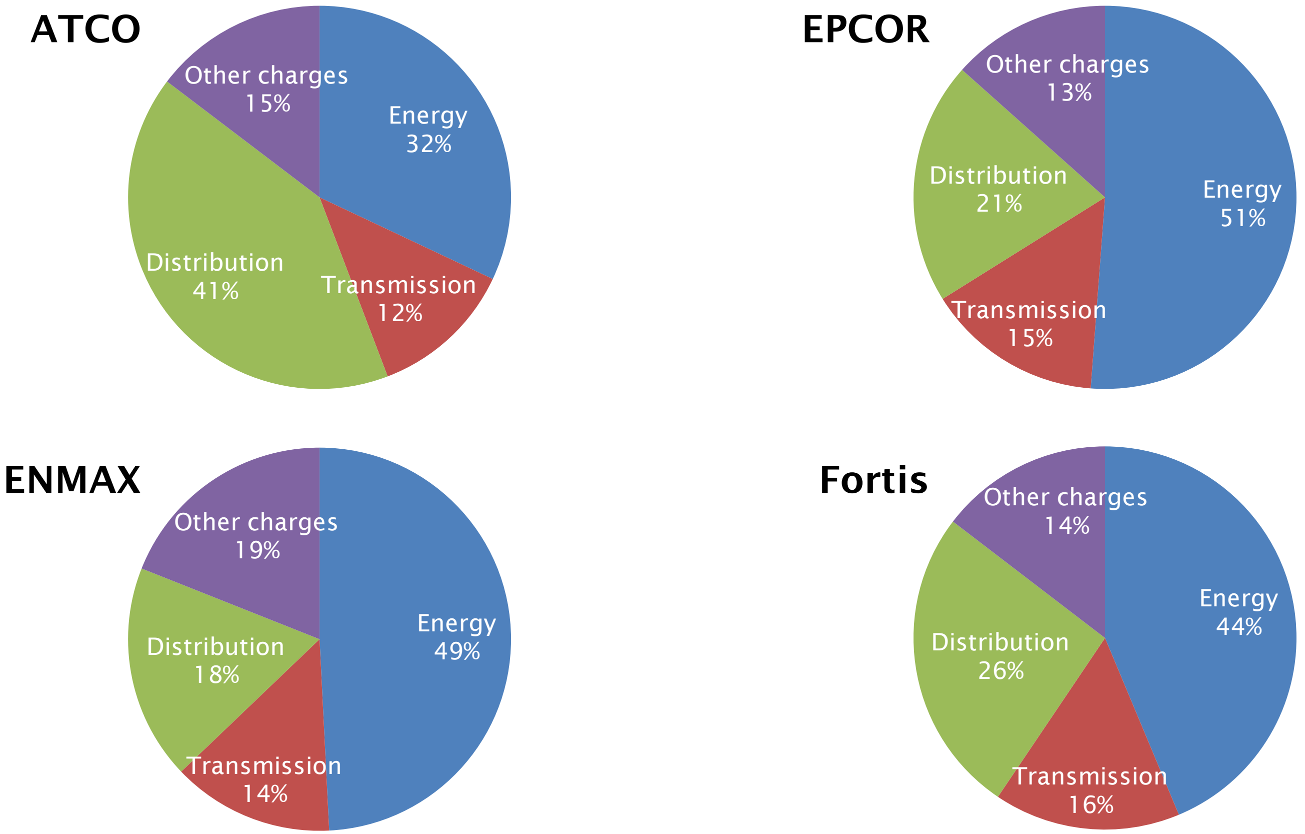
  - LEI estimates ~$1.9 billion in additional transmission capital costs would be needed over the 2024-2040 period to support the ~4.5 GW of additional renewables added in LEI's More Renewables Cases; this would increase transmission rates by at most $2/MWh under the More Renewables Cases relative to the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

LE LONDON ECONOMICS

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**

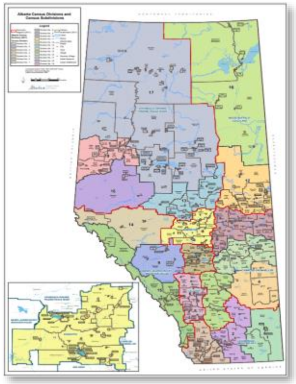
- LEI leveraged Guidehouse's 2024 Net-Zero Analysis of Alberta's Electricity Distribution System Report, which estimates integration costs associated with varying levels of solar DERs and EVs; LEI rescaled the Guidehouse estimates to align with the level of DERs and EVs forecasted in AESO's preliminary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

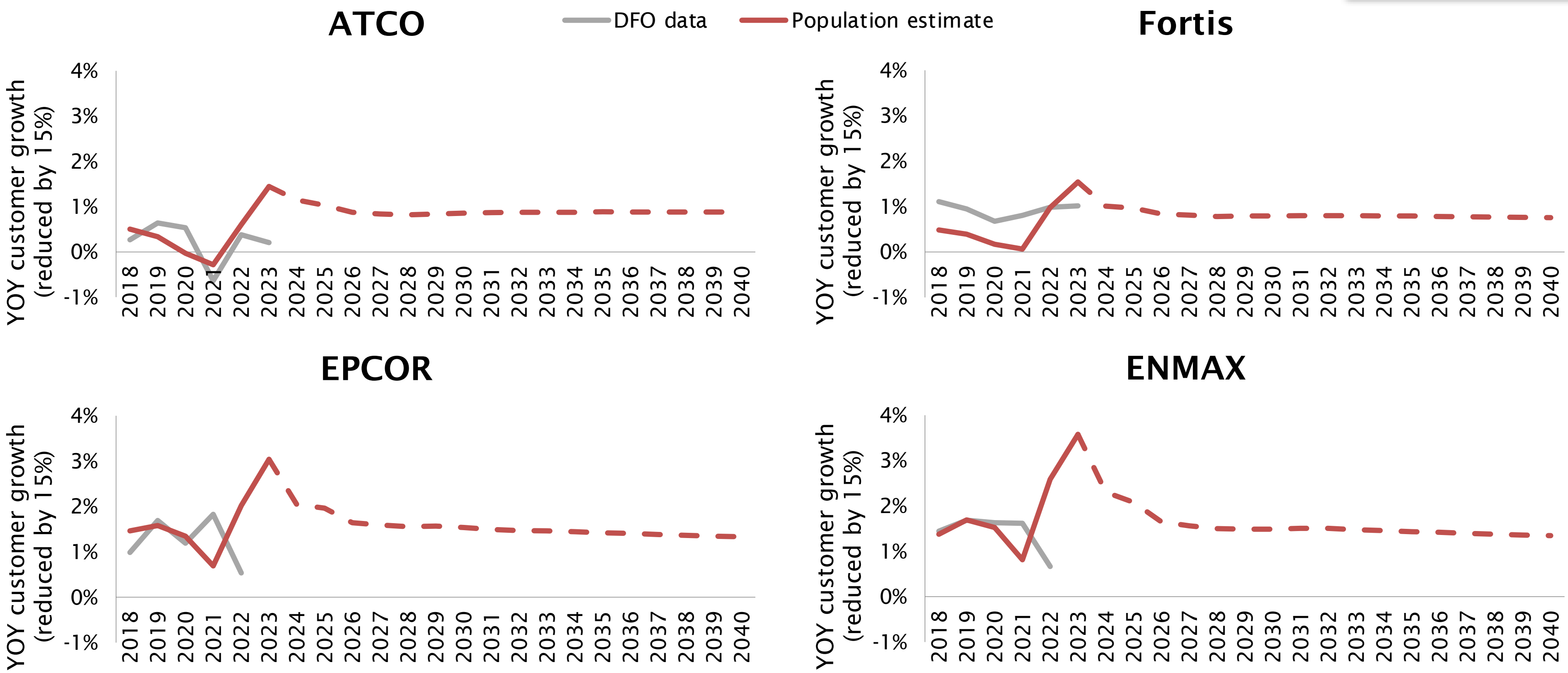
LONDON ECONOMICS

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.

LONDON ECONOMICS

Agenda

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)

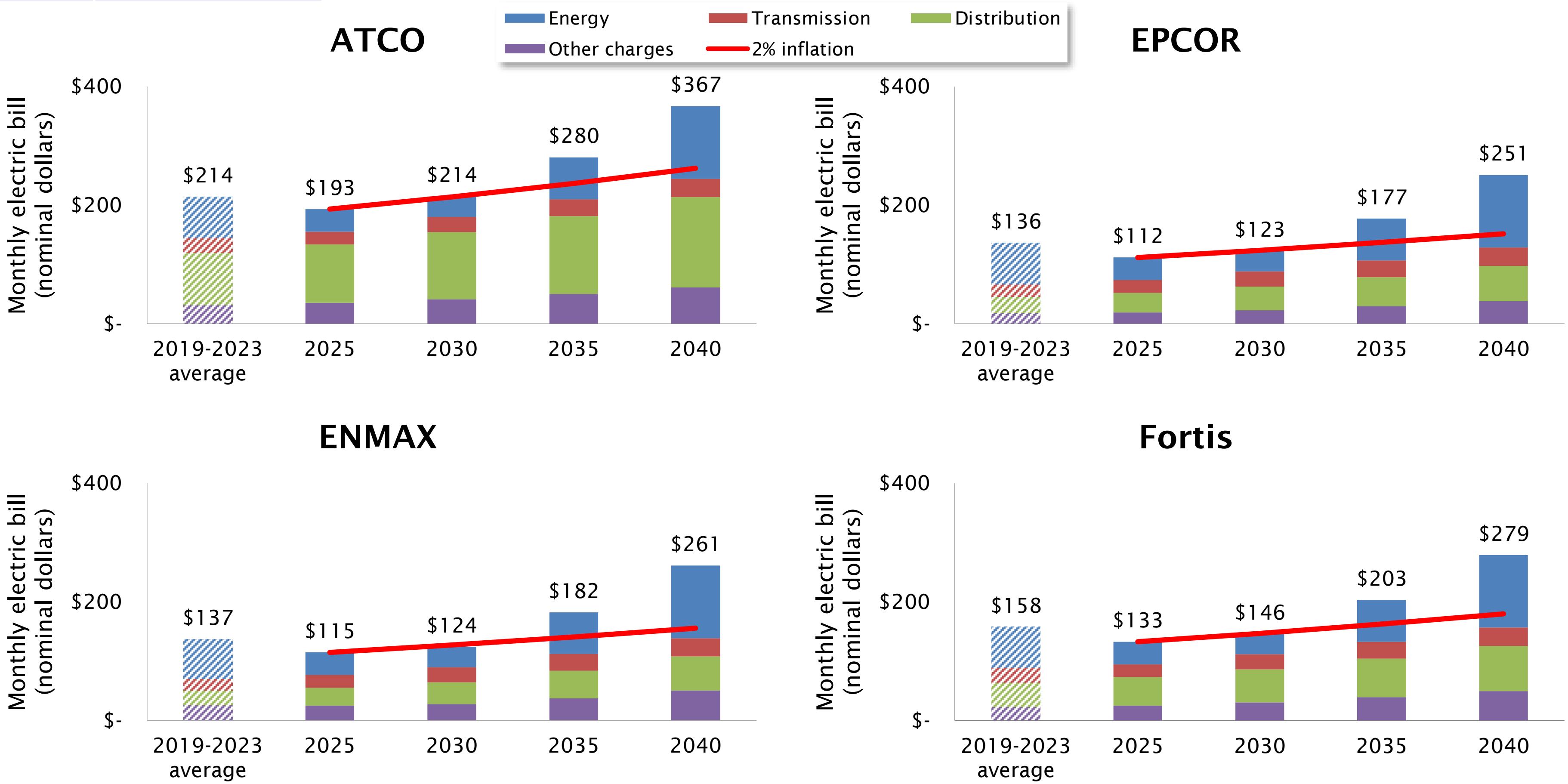
DFO	2025-2030 CAGR	2030-2040 CAGR
ATCO	2.4%	3.6%
EPCOR	2.4%	4.5%
ENMAX	2.2%	4.5%
Fortis	2.4%	4.1%
Province avg.	**2.4%**	**4.2%**

* 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)

2035 Base Case

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

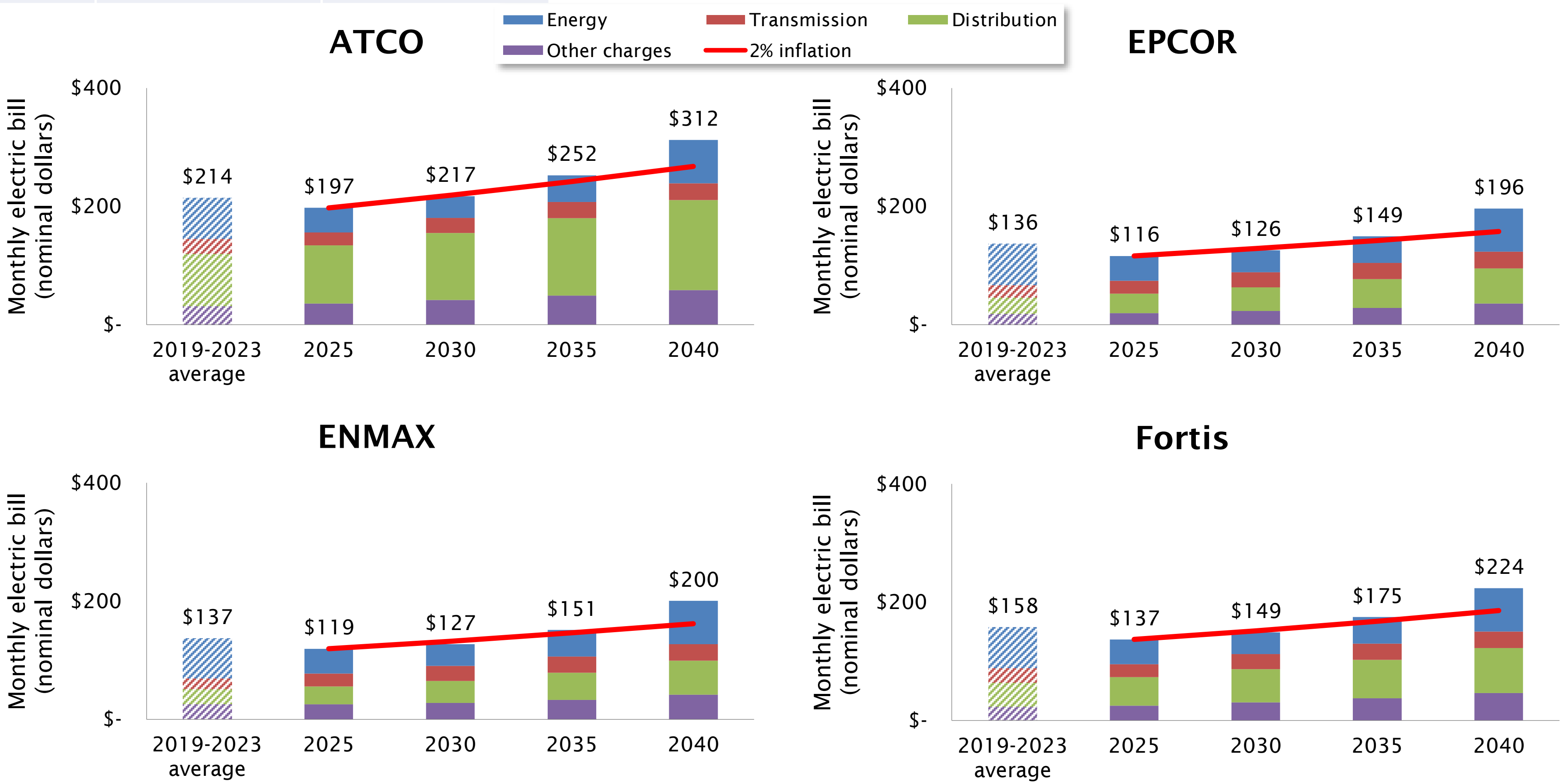


LE LONDON ECONOMICS

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

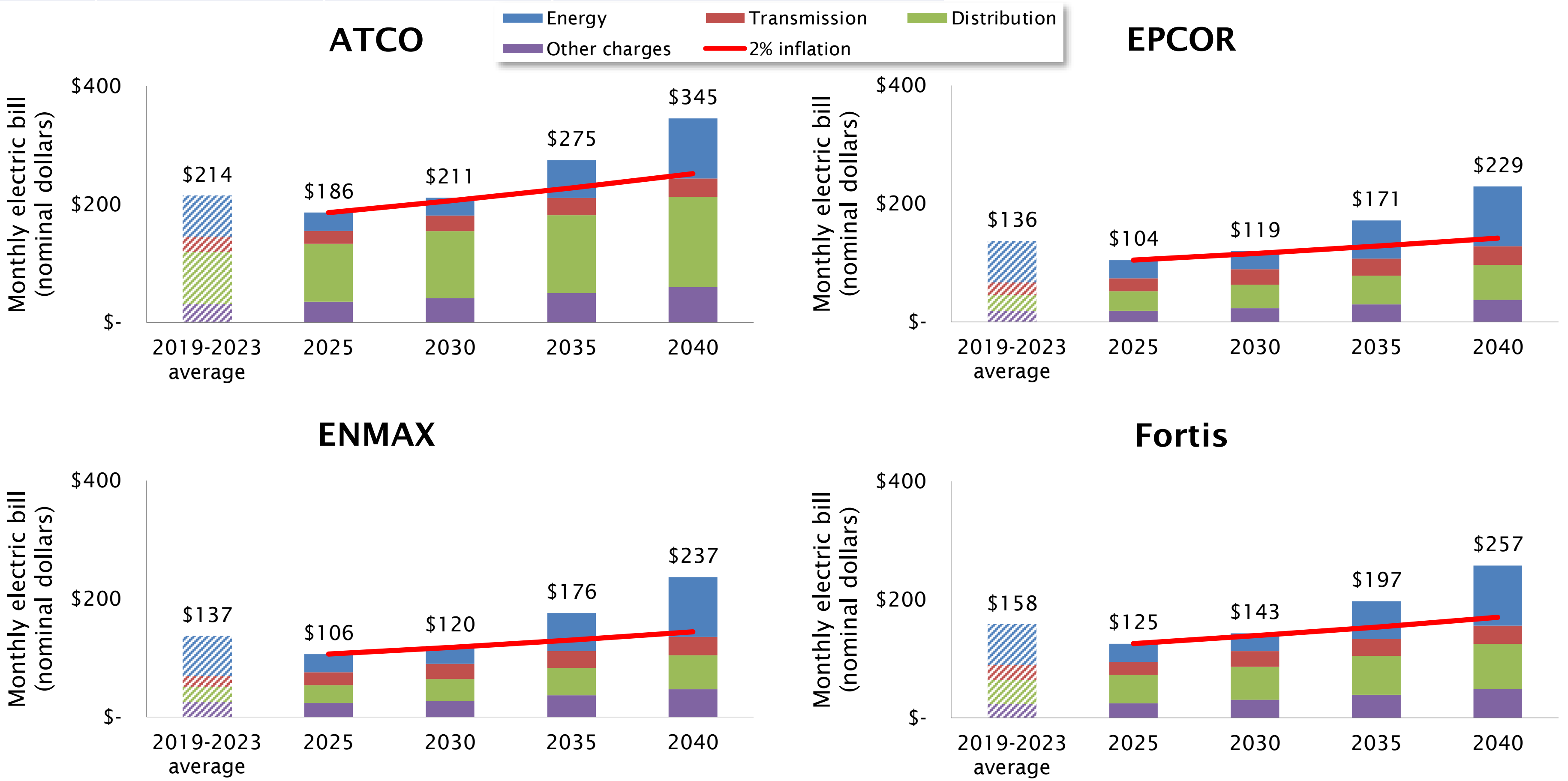


LONDON ECONOMICS

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%

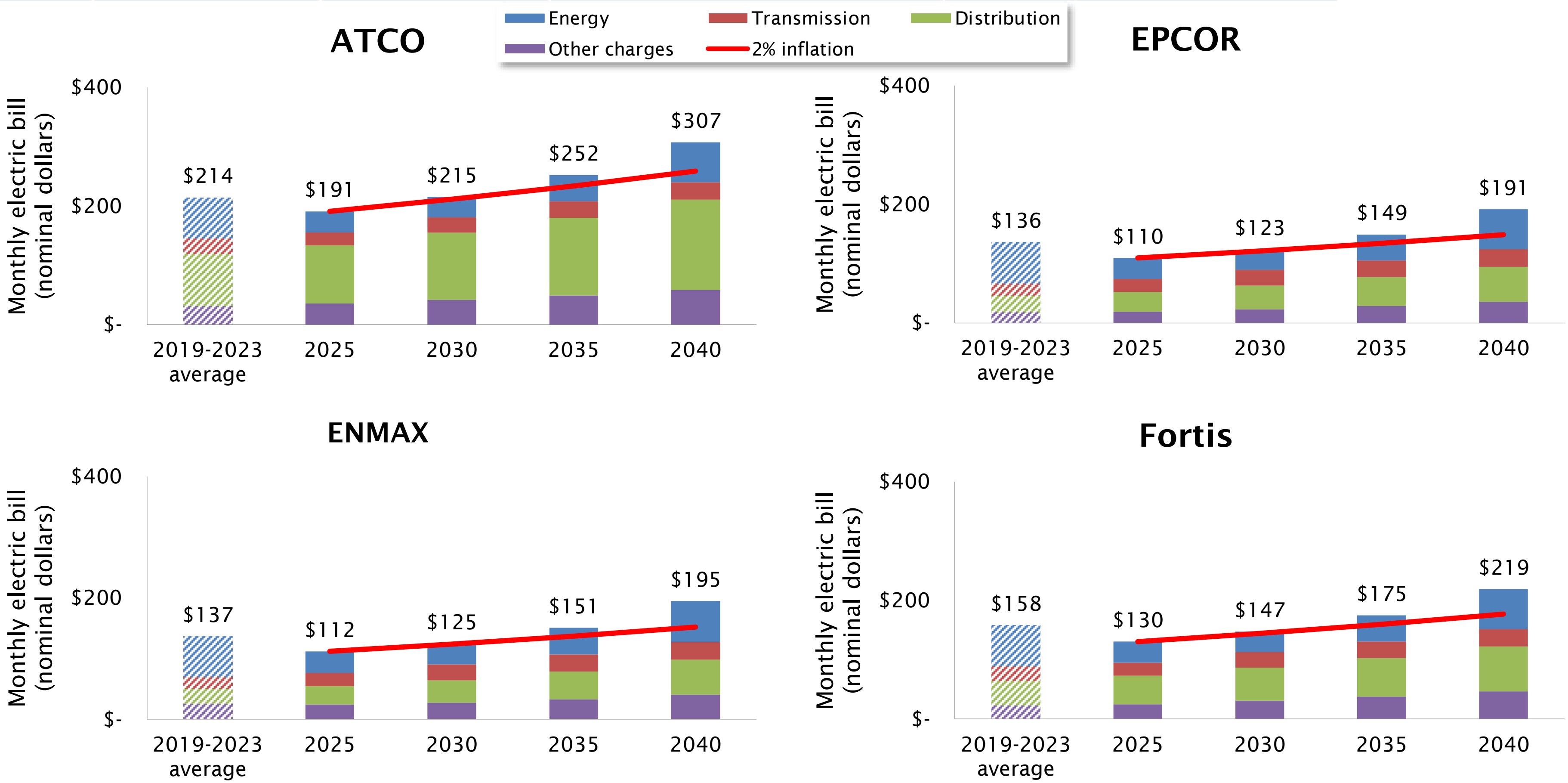
2035 More Renewables Calibrated Case



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

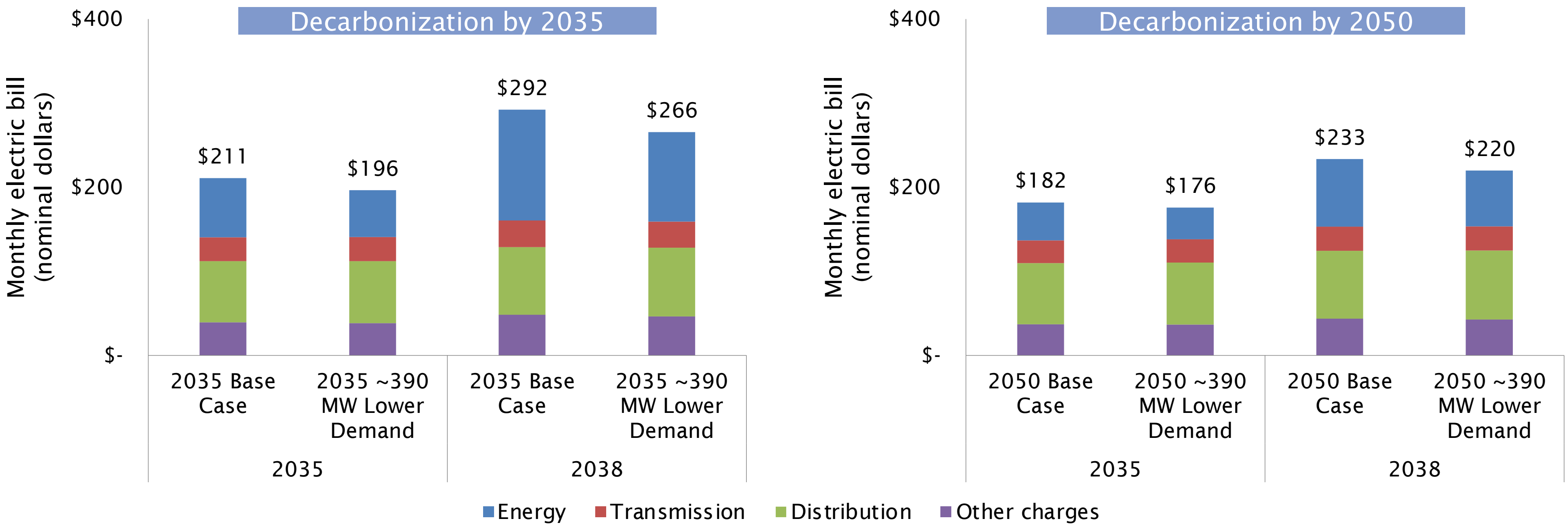


LE LONDON ECONOMICS

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



LONDON ECONOMICS

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

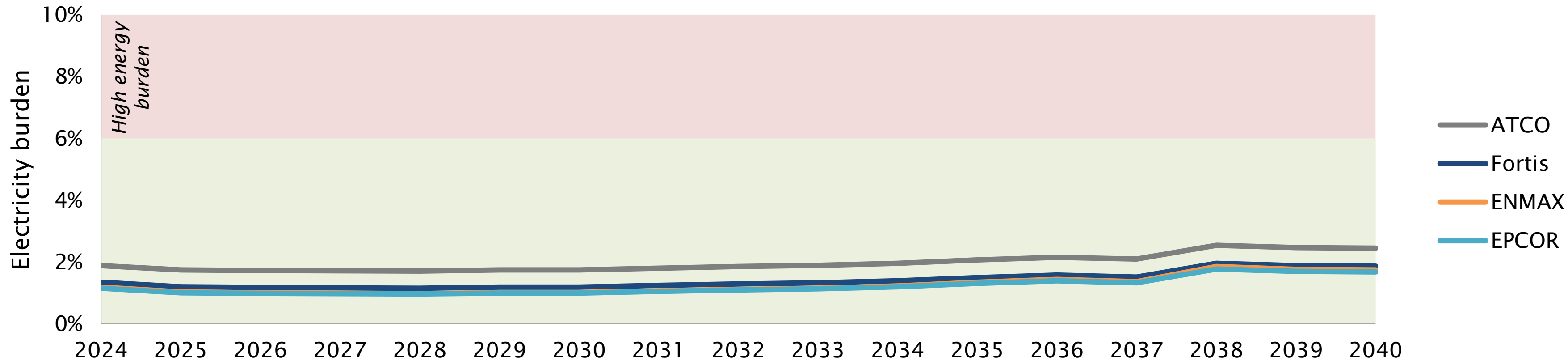
- LEI's electric bill impact analysis is paired with the reliability outcomes discussed in Annex 1 *(Scenario Analysis: Long Term Weather-Normal Energy Market Forecast)*, which anticipates lower levels of electric service reliability than Albertans have become accustomed to

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

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%**

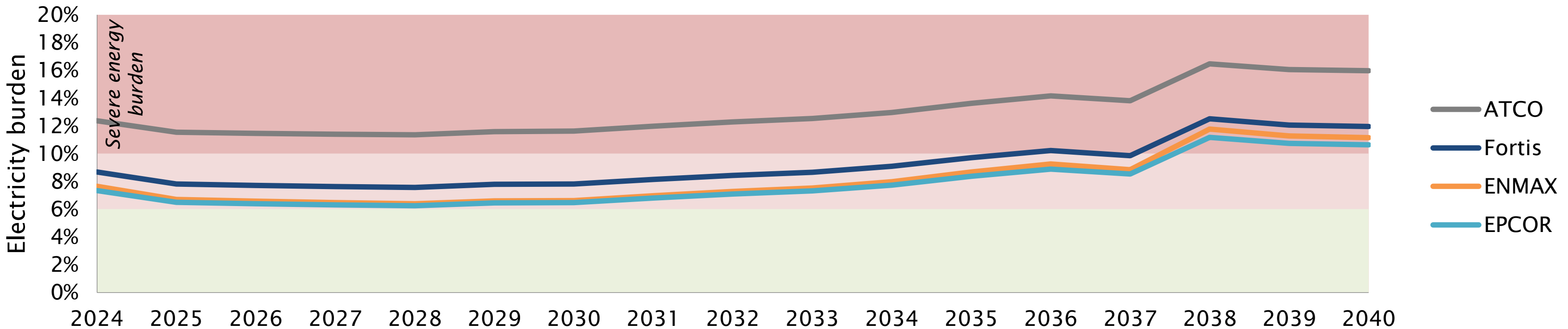
See for example Fisher, Sheehan & Colton. *Home Energy Affordability Gap*; Alberta average total income from Statistics Canada Table 11-10-0190-01.

LE
LONDON ECONOMICS

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.

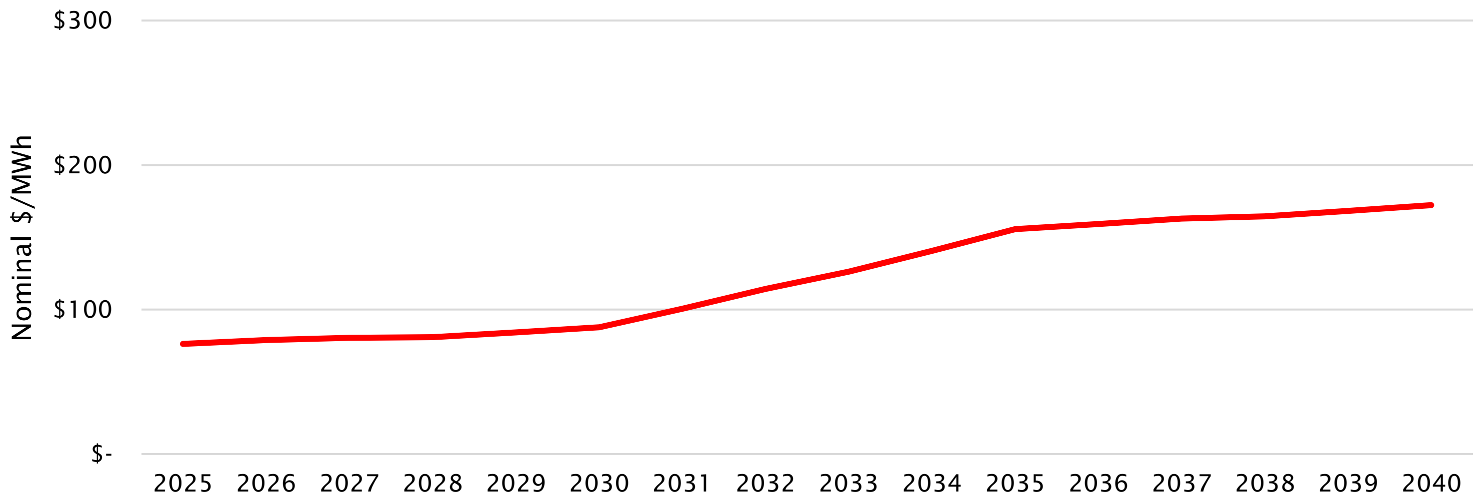
Sources: Statistics Canada Tables 11-10-0192-01 and 25-10-0062-01, 1 GJ = 277.7778 kWh (*see* Canada Energy Regulator. *Energy conversion tables*)

LONDON ECONOMICS

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)

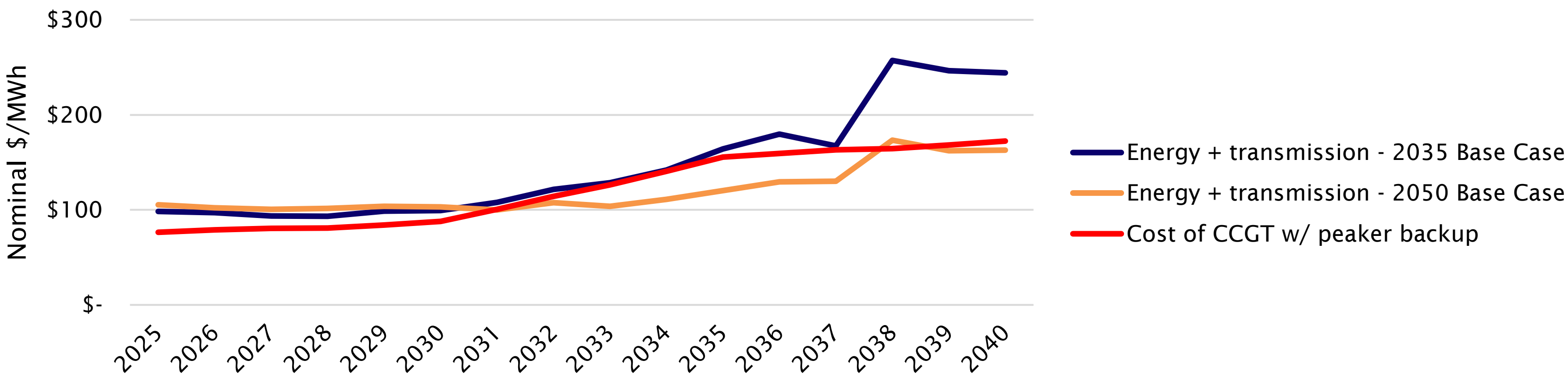


Note: Levelized cost increases over time due to gas prices and carbon costs.

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)

Bibliography of information and data sources relied upon for LEI's bill impact analysis (1 of 3)

AESO. *2022 Annual Market Statistics.* March 2023.

AESO. *2022 Transmission Rate Projection.* April 2022.

AESO. *2024 ISO Tariff Update Application – Appendix B: 2024 Rate Calculations.* November 16, 2023.

AESO. *2024 ISO Tariff Update Application – Appendix C: 2024 Escalation Factor and Investment Levels.* November 16, 2023.

AESO. *2024 LTO Preliminary Data File.* November 15, 2023.

AESO. *AESO 2022 Long-term Transmission Plan.* January 2022.

AESO. *AESO Net-Zero Emissions Pathways Report.* June 2022.

AESO. *AESO Stakeholder Symposium.* November 30, 2023.

AESO. *Delivered Cost of Electricity Report.* May 2020.

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

AltaLink. *2024-2025 GTA – MFR Schedules (Exhibit 28174_X0007.01).* August 31, 2023.

ATCO. *2023 Price Schedules.* Effective January 1, 2023.

ATCO. *Annual Franchise Fee Adjustment.* December 13, 2023.

ATCO. *Compliance Filing for 2023-2025 General Tariff Application (GTA) and Negotiated Settlement Agreement (NSA) – Attachment 4 (Exhibit 28252_X0005.01).*

AUC. *Decision 27388-D01-2023, 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities.* October 4, 2023.

AUC. *Monthly regulated rate option rates.*

BMO. *Provincial Economic Outlook.* December 1, 2023.

Canada Energy Regulator. *Energy conversion tables.*

CIBC Capital Markets. *Provincial Budget Briefs.* February 28, 2023.

City of Edmonton. *2023 Electric Power Franchise Fee Rate Notification.* September 28, 2022.

Bibliography of information and data sources relied upon for LEI's bill impact analysis (2 of 3)

Direct Energy Regulated Services. *Electricity RRT 2024 interim rate schedules.* Effective January 1, 2024.

ENMAX. *2023 Regulated Rate Option Tariff.* Effective September 1, 2023.

ENMAX. *2023-2025 General Tariff Application – Appendix A (Exhibit 27581_X0017).*

ENMAX. *2024 Rate Schedules.* Effective January 1, 2024.

ENMAX. *Local Access Fee (LAF).*

ENMAX. *The regulated rate option (RRO).*

EPCOR. *2023-2025 TFO TA – Attachment 3 (Exhibit 27675_X0172.01).*

EPCOR. *DAS Tariff.* Effective January 1, 2024.

EPCOR. *Interim price schedule for EDTI.* Effective January 1, 2023.

EPCOR. *Interim price schedule for Fortis.* Effective January 1, 2023.

EPCOR. *SAS Tariff.* Effective January 1, 2024.

Fisher, Sheehan & Colton. *Home Energy Affordability Gap.*

Fortis. *2023 Rate Schedules.* Effective January 1, 2023.

Fortis. *Municipal assessment Rider A-1.* Effective July 1, 2023.

Fortis. *Municipal franchise fee schedule.* Effective January 1, 2024.

Government of Alberta. *2023-24 Mid-year Fiscal Update and Economic Statement.* November 2023.

Government of Alberta. *Alberta Municipal Affairs Population List.* February 19, 2021.

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

Guidehouse. *Net-Zero Analysis of Alberta's Electricity Distribution System.* January 22, 2024.

Market Surveillance Administrator. *Quarterly Report for Q3 2023.* November 15, 2023.

Bibliography of information and data sources relied upon for LEI's bill impact analysis (3 of 3)

RBC Economics. *Provincial Outlook.* September 2023.

Scotiabank. *Slowdown Underway But Risks Mounting.* October 23, 2023.

Statistics Canada. *Consumer Price Index, monthly, not seasonally adjusted (Table 18-10-0004-01).* January 16, 2024.

Statistics Canada. *Fixed weighted index of average hourly earnings for all employees, by industry, monthly (Table 14-10-0213-01).* January 25, 2024.

Statistics Canada. *Household energy consumption, by household income, Canada and provinces (Table 25-10-0062-01).* May 2, 2022.

Statistics Canada. *Market income, government transfers, total income, income tax and after-tax income by economic family type (Table 11-10-0190-01).* May 2, 2023.

Statistics Canada. *Upper income limit, income share and average income by economic family type and income decile (Table 11-10-0192-01).* May 2, 2023.

TD Economics. *Provincial Economic Forecast.* September 30, 2023.

LONDON ECONOMICS

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.

The contents of LEI's analysis do not constitute investment advice. LEI, its officers, employees, and affiliates make no representations or recommendations to any party other than the AUC. LEI expressly disclaims any liability for any loss or damage arising or suffered by any third party as a result of that party's, or any other party's, direct or indirect reliance upon LEI's analysis.