   

Ontario Wholesale Electricity Market Price Forecast

For the Period November 1, 2021 through April 30, 2023

Prepared for: Ontario Energy Board

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POWER ADVISORY

EXECUTIVE SUMMARY

Power Advisory LLC (Power Advisory) was engaged by the Ontario Energy Board (OEB) to produce a forecast of wholesale electricity market prices in Ontario for the November 1, 2021 to April 30, 2023 period. This wholesale electricity price forecast will be used by the OEB, as one of a number of inputs, to set the Regulated Price Plan (RPP) prices for eligible consumers under the *Ontario Energy Board Act, 1998*.

Power Advisory used a complex model of Ontario's electricity market to forecast the Hourly Ontario Electricity Price (HOEP). The model combines regression analysis and dispatch modelling to generate hourly price curves that are consistent with historical market behaviour and reflective of forward-looking analysis that predicts market changes. Amongst other data, the model reflects Ontario's electricity demand and hourly load shape, all committed new entrant generation, all planned generation retirements, the operating profiles of Ontario's hydroelectric generation (including both baseload and peaking resources), the operating characteristics of Ontario's thermal generation, and expected fuel and carbon prices. The assumptions used by Power Advisory and their sources are discussed in detail in Chapter 3 of this report.

Table ES-1 presents the results of the base case market price forecast resulting from Power Advisory's modelling. The prices presented are simple averages (i.e., not load-weighted).

Table ES-1: HOEP Forecast ($ CAD per MWh)

Calendar Period	On-Peak	Off-Peak	Average
Nov 2021 - Jan 2022	$43.09	$25.63	$33.61
Feb 2022 - Apr 2022	$43.43	$31.87	$37.13
May 2022 - Jul 2022	$33.43	$18.54	$25.39
Aug 2022 - Oct 2022	$35.62	$22.49	$28.51
Nov 2022 - Jan 2023	$43.76	$29.11	$35.81
Feb 2023 - Apr 2023	$43.19	$32.94	$37.60
Nov 2021 - Apr 2023	$40.39	$26.70	$32.96

Source: Power Advisory

Notes:

1) Assumes natural gas prices that reflect an average of the exchange rate forecasts of five major Canadian banks (Bank of Montreal, Canadian Imperial Bank of Commerce, Royal Bank, Scotiabank, and Toronto-Dominion) as reported in their public economic forecasts as of September 29, 2021. For the November 2021 to April 2023 HOEP forecast period, the average exchange rate is US$1 = C$1.26.

2) On-peak hours are between 7 a.m. and 11 p.m. Eastern Standard Time (EST) on non-holiday weekdays. Off-peak hours are all other hours (weekends, holidays, and overnight). The times for the calculation of on-peak and off-peak hours are not adjusted for Daylight Savings Time (DST).

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1. INTRODUCTION

Power Advisory LLC (Power Advisory) was engaged by the Ontario Energy Board (OEB) to produce a forecast of wholesale electricity market prices in Ontario for the November 1, 2021 to April 30, 2023 period (forecast period). This wholesale electricity price forecast will be used by the OEB, as one of a number of inputs, to set November 1, 2021 Regulated Price Plan (RPP) prices for eligible consumers under the *Ontario Energy Board Act, 1998*. Wholesale electricity prices affect the RPP supply cost and the resulting RPP prices by determining RPP-weighted wholesale electricity costs, and by affecting payments to regulated and contracted generators that are funded through the Global Adjustment.

This report presents the results of Power Advisory's forecast, the key assumptions driving this forecast, and the information sources on which these assumptions were based.

1.1 Contents of This Report

This report is organized into four chapters, starting with this introduction. Chapter 2 outlines the price forecasting methodology and identifies the key forecast drivers. Chapter 3 reviews the forecast assumptions and identifies the information sources on which these assumptions are based. Chapter 4 presents the Ontario wholesale electricity market price forecast results.

2. PRICE FORECASTING METHODOLOGY

2.1 Overview of Ontario's Wholesale Electricity Market

Wholesale prices in Ontario are determined by the Independent Electricity System Operator (IESO) based on provincial electricity demand and the monies paid to generators to supply it. Generators supplying electricity to the Ontario wholesale market must offer their output to the IESO as a series of hourly price and quantity pairs. Based on these offers, the IESO uses a dispatch algorithm to choose the least-cost combination of generation resources which can meet forecast demand in each five-minute interval of each hour. The selection of resources based on cost is subject to technical factors such as ramp rates for gas-fired generation, transmission constraints, and other physical limitations.

For each five-minute interval, the offer price of the most expensive generation selected becomes the Market Clearing Price (MCP) for that period. Each generator in Ontario receives the MCP for its energy output, regardless of what price it offered to the IESO. For each hour, the twelve five-minute MCPs are averaged to determine the Hourly Ontario Electricity Price (HOEP). Thus, the interaction of hourly supply and demand determines Ontario's wholesale electricity market price.

2.2 Overview of the Forecasting Model

The major factors known to drive the equilibrium between electricity supply and demand in Ontario are reflected in Power Advisory's HOEP Forecast Model. Accordingly, the model reflects the history of the Ontario electricity market and specifically the relationship between the drivers of market prices and the resulting market prices. This relationship is then extrapolated forward to produce a forecast of expected wholesale electricity prices.

However, no model can accurately simulate all of the factors and interactions that affect prices in an electricity market the size of Ontario's. In order to retain as much historical information as possible regarding the nuances of market operation, the starting point for Power Advisory's model is hourly prices over the past five years (2016-2020). For each forecast year, the model takes the hourly prices for the first historical base year (2016), reflecting supply, demand, fuel prices, weather, etc. in that year, and adjusts each of these 8,760 hourly prices[1] based on expected changes in supply, demand, and fuel prices in each forecast year. For example, if the amount of nuclear capacity in-service in the forecast year is expected to be less than what was available in the base year, supply will be reduced, and prices correspondingly increased to reflect the revised supply mix, in all hours of the forecast year. If more wind capacity is expected to be in service, supply in the forecast year is increased, but with a greater impact on prices in hours which experienced greater wind in the base year. The relationship between supply, demand, and price is established through regression analysis as part of the modelling process. Prices are

[1] In leap years, February 29 is excluded. As a result, every year is modeled as having 8,760 hours.

further adjusted to reflect market rules on curtailment of wind, solar, and nuclear generation, as appropriate. The process is repeated for the same forecast year using each of the remaining four historical base years (2017, 2018, 2019 and 2020), and the results using all five base years are averaged to produce the forecasts shown in this report.

2.3 Key Forecast Drivers

Although other influences exist, forecast price changes are driven by three primary factors:

- Hourly demand for electricity, including both changes in total monthly or annual demand, and changes in the time of day when consumers use electricity.
- Generation in service, taking into account capacity additions (such as wind, solar, hydro, gas and other facilities coming into service), retirement of older capacity, the expiration of generation contracts and temporary shut-downs, especially for the refurbishment of the Bruce and Darlington nuclear plants.
- Cost of burning natural gas, including both the market price of natural gas and the costs due to greenhouse gas (GHG) emissions. The marginal cost of generating electricity from natural gas is an important determinant of electricity prices in Ontario in many hours during the forecast period. When Ontario demand is high relative to supply, the marginal source of supply (which either sets or strongly affects the MCP) is usually either domestic gas generation, or imports from other markets where the price is often set by natural gas generation. When supply is high relative to Ontario demand, the province exports electricity to neighbouring markets, and the price received is often set by the cost of natural gas generation in those markets.

3. KEY FORECAST ASSUMPTIONS

The major assumptions used in the HOEP forecast model, as well as their sources, are presented below.

3.1 Demand Forecast

The basis for Power Advisory's energy demand forecast is the IESO's *Reliability Outlook: An adequacy assessment of Ontario's electricity system October 2021 to March 2023* (released September 23, 2021) (*Reliability Outlook)*.[2] The IESO's forecast contained in this report takes conservation and demand management programs into account. It assumes "normal weather" – i.e., the energy forecast is based on daily weather conditions that are representative of typical weather conditions for that time of year. It also takes into account the impact on demand of the COVID-19 pandemic. For the September 2021 through September 2022 period, the demand forecast in the current *Reliability Outlook* (dated September 23, 2021) overlaps with that in the Reliability Outlook published in March 2021 that informed May 1, 2021 RPP prices. The two forecasts are not materially different.

The IESO forecasts demand at the transmission grid level. However, Ontario has a significant and growing supply of generation "embedded" in the distribution network, which supplies a corresponding volume of consumer demand that does not pass through the transmission system. Therefore, the IESO adjusts its forecast of grid-level demand to exclude embedded generation (technically, to exclude the demand that it supplies). Power Advisory's HOEP forecast model takes into account both grid-level demand, and the demand supplied by embedded generation.

The forecast period for this report (November 1, 2021 - April 30, 2023) extends slightly beyond the energy forecast period covered by the IESO's *Reliability Outlook* and therefore Power Advisory has extrapolated the IESO's forecast to cover the entire forecast period. Table 1 shows the forecast of monthly energy consumption used in the model.

[2] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2021Sep.ashx

Table 1: Forecast Monthly Energy Consumption and Peak Demand

Month	Grid-Level Demand (TWh)	Embedded Demand (TWh)	Total Demand (TWh)	Peak Grid Demand (MW)
Nov 2021	10.89	0.48	11.37	19,227
Dec 2021	11.98	0.45	12.44	20,089
Jan 2022	12.49	0.47	12.96	20,940
Feb 2022	11.17	0.49	11.66	20,331
Mar 2022	11.59	0.52	12.11	19,483
Apr 2022	10.23	0.63	10.87	17,265
May 2022	10.43	0.62	11.05	18,271
Jun 2022	11.00	0.64	11.65	22,184
Jul 2022	11.92	0.61	12.52	22,555
Aug 2022	12.04	0.58	12.62	22,427
Sep 2022	10.50	0.51	11.01	21,331
Oct 2022	10.56	0.50	11.06	17,392
Nov 2022	11.11	0.48	11.59	19,520
Dec 2022	12.14	0.45	12.60	20,155
Jan 2023	12.67	0.48	13.15	21,248
Feb 2023	11.41	0.49	11.89	20,760
Mar 2023	11.87	0.52	12.40	19,960
Apr 2023	10.25	0.63	10.88	17,297
Total/Maximum	204.27	9.56	213.83	22,555

Source: IESO, Reliability Outlook (September 23, 2021), Tables 3.1.1 and 3.3; Power Advisory

3.2 Supply Resources

Power Advisory's generation capacity assumptions are consistent with the IESO's *Reliability Outlook*. Assumptions regarding expected generation capacity additions, available nuclear capacity and hydro generation, and Ontario's interconnection limits are detailed below.

3.2.1 Generation Capacity Additions

In addition to the existing supply resources, two major wind projects (Romney Wind Energy Centre and Nation Rise) are expected to come on-line during the forecast horizon, as listed in Table 2. These have been included in the model specification. The supply contract of one biofuel generator (Calstock), one gas generator (Iroquois Falls), and two gas/oil generators (Lennox and

Nipigon) will expire during the forecast period. Lennox's contract is expected to be renewed and therefore its full capacity is reflected in the forecast.[3]

Table 2: Major Generation Capacity Changes

Project Name	Resource Type	Capacity (MW)	Estimated Effective Date
Calstock	Biofuel	-38	2021-Q4
Iroquois Falls	Gas	-131	2021-Q4
Lennox GS	Gas/Oil	-2200	2022-Q4
Nipigon GS	Gas/Oil	-23	2022-Q4

Source: IESO, Reliability Outlook (September 23, 2021), Table 4.2.

In addition to the transmission-connected projects shown in Table 2, the tables accompanying the IESO's *Reliability Outlook* forecast the addition of 6 MW of distribution-connected hydro projects during the forecast period. Including the above additions, the model assumes that 2,500 MW of solar capacity and 5,500 MW of wind capacity will be in service by April 2023, capable of generating enough electricity to meet approximately 12% of Ontario's demand. Increases in solar and wind generation put downward pressure on Ontario's wholesale electricity prices.

3.2.2 Nuclear Capacity

Unit 2 of the Darlington Nuclear Generating Station returned to service in June 2020 following its refurbishment, while unit B6 of the Bruce Nuclear Generating Station and Unit 3 of Darlington were taken out of service for refurbishment in January and July 2020, respectively. Unit 1 of Darlington and Unit 3 of Bruce are expected to begin refurbishment in the first quarter of 2022[4] and the first quarter of 2023[5] respectively. The fourth Darlington unit, and the remaining four Bruce units, are also scheduled to undergo refurbishment, but not before the end of the forecast period.

Based on this, and historical generation patterns, the HOEP forecast model assumes total nuclear generation of 115 TWh over the forecast period, as shown in Table 3 below. This implies a capacity factor of 84.4%, which is calculated as the average power generated over the rated peak power available through the nuclear fleet, excluding the units which are out of service. It

[3] The IESO's September 23, 2021 Reliability Outlook Report indicates that the IESO and OPG are engaged in bilateral negotiations on a contract extension. Accordingly, the forecast assumes Lennox will be in service and will receive payments for its supply in amounts that reflect its current contract terms throughout the forecast period. .

[4] https://www.opg.com/strengthening-the-economy/our-projects/darlington-refurbishment/

[5] IESO, 2020 Annual Planning Outlook (https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Annual-Planning-Outlook-Dec2020.ashx), Figure 11

takes into account expected curtailment of some of the Bruce units during times when domestic supply exceeds demand. All plants show higher capacity factors during summer and winter and lower capacity factors during the shoulder seasons (spring and fall), indicative of the planned maintenance that tends to be scheduled for the shoulder seasons when demand is lower.

Table 3: Forecast Nuclear Generation

Month	Nuclear Generation (TWh)
Nov 2021	6.84
Dec 2021	7.27
Jan 2022	7.54
Feb 2022	6.36
Mar 2022	6.28
Apr 2022	5.85
May 2022	5.87
Jun 2022	6.37
Jul 2022	6.99
Aug 2022	6.86
Sep 2022	6.21
Oct 2022	6.53
Nov 2022	6.28
Dec 2022	6.67
Jan 2023	6.40
Feb 2023	5.40
Mar 2023	5.80
Apr 2023	5.40
Total	114.93

Source: Power Advisory

3.2.3 Hydro Generation

Hydroelectric generation can vary significantly from year to year depending on the level of precipitation in the province. The starting point for Power Advisory's HOEP forecast model is historical supply and demand for the five base years (2016-2020). During these years, annual output of transmission-connected hydro ranged from a low of 35.0 TWh in 2016 to a high of 36.9 TWh in 2017. This range is reflected in the forecast, which is based on an average of the forecast developed using each of the five base years. The forecasts of hydro output are adjusted for changes in installed hydro capacity between the forecast year and the base year (such as the addition of 6 MW of embedded hydro capacity during the forecast period).

3.2.4 Transmission Capabilities and Constraints

Unlike many electricity systems which have different electricity prices in different areas, Ontario has a uniform electricity price that applies across the entire province. HOEP therefore does not directly reflect transmission constraints within Ontario. The forecast model reflects this, and does not model internal transmission constraints. To the extent that transmission constraints have indirect impacts on wholesale market prices, these are implicitly factored into the model through the use of historic price curves.

External transfer limits can also affect Ontario prices. Limited transfer capability can mean higher prices when demand exceeds supply, because less expensive imports cannot be brought in. Similarly, when supply exceeds demand, suppliers may be unable to sell their surplus in other markets due to transfer limits. The transfer capabilities of transmission interconnections with adjacent markets are shown in the IESO's *Reliability Outlook*, differentiated by season and direction of flow. Table 4 shows the ratings of Ontario's interconnections with adjacent markets based on the information presented in the IESO's *Reliability Outlook*.

Table 4: Ontario Interconnection Limits

(MW)	Flows Out of ON		Flows Into ON	
	Summer	Winter	Summer	Winter
Manitoba	210	300	210	300
Minnesota	150	150	100	100
Michigan	1,650	1,650	1,550	1,700
New York	1,950	2,100	1,800	1,950
Québec	2,145	2,165	2,330	2,350

Source: IESO, Reliability Outlook (September 23, 2021), Table B3

3.3 Natural Gas Prices

Given the uncertainty associated with fuel price forecasts, Power Advisory typically relies on liquid financial and physical markets to specify natural gas market price forecasts. For Ontario electricity prices, the most relevant pricing hub is the Dawn/Union hub in Southwestern Ontario. While trade volumes at this hub are lower, and therefore less widely reported than at other gas hubs, Natural Gas Intelligence reports forward prices for up to ten years into the future, based on trades brokered by OTC Global Holdings. Power Advisory uses these prices in its forecasts.

Future prices based on trading over a single day may be pushed up or down by very short-term factors that do not reflect long-term trends. To reduce the impact of such volatility on forecast prices, an average of settlement prices over the most recent 21 days is used.

These forward prices are reported in US dollars and therefore must be converted into Canadian dollars. The price forecast reflects an average exchange rate of $1.26 CAD per USD between May 2021 and April 2023. The monthly exchange rate forecast is based on an average of the exchange rate forecasts of five major Canadian Banks (Bank of Montreal, Canadian Imperial Bank of Commerce, Royal Bank, Scotiabank, and Toronto-Dominion) as reported in their public economic forecasts as of September 29, 2021. As well as affecting the forecast of the natural gas price in Ontario, the forecast exchange rate affects the price of electricity imports from, and exports to, neighbouring markets.

3.3.1 GHG Emission Allowance Price Forecast

The HOEP forecast takes into account the cost of GHG emission allowances incurred when burning natural gas to generate electricity.

Effective January 1, 2019, gas-fired generation in Ontario (as well as in some other provinces) has been subject to Part II of the federal government's *Greenhouse Gas Pollution Pricing Act*, and the associated Output-Based Pricing System Regulations[6]. That legislative regime introduced an output-based pricing system (OBPS), including compliance benchmarks, and prices on emissions above those benchmarks.

On March 29, 2021, the government of Canada announced that it had accepted the province's Emissions Performance Standards (EPS) program as an alternative to the OBPS system, and that the province would transition from the OBPS to the EPS as of January 1, 2022.[7] The EPS system is quite similar to the OBPS system, including identical charges for excess emissions: $40 per tonne of carbon dioxide equivalents (CO_2e) emitted in 2021, and $50 per tonne in 2022. One difference is in the benchmark above which excess emission charges would need to be paid: 370 tonnes/GWh in the federal OBPS compared to 420 tonnes/GWh in Ontario's EPS.[8] Generators in Ontario are assumed to be subject to the 370 tonnes/GWh benchmark in 2021, and to the 420 tonnes/GWh benchmark in 2022 and 2023. The excess emission charge under the EPS is assumed to increase to $65 per tonne in 2023 in order to meet the requirements of the federal government's *Pan-Canadian Framework on Clean Growth and Climate Change*.[9]

Participants in the EPS are required to report and manage their own carbon-related compliance obligations. If their annual emissions exceed their sector-based emission intensity benchmark, they must either pay for compliance units at the above carbon prices, or purchase compliance units from another facility.

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[6] https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/index.html

[7] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system.html

[8] A regulatory change has been proposed to change the EPS benchmark to 370 tonnes/GWh; see https://ero.ontario.ca/notice/019-3719 . This has not been reflected in the forecast as it has not been finalized. The impact on the forecast would be small, because both benchmarks are close to the operating characteristics of much of Ontario's fleet of gas generators.

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

The following example illustrates how the excess emissions charge payable by Ontario's gas-fired generators is calculated: a combined-cycle plant that emitted 430 tonnes of CO_2e in the process of generating 1 GWh of electricity would pay $2,400 in excess emissions charges in 2021. The $2,400 charge is determined based on CO_2e emissions of 60 tonnes (being the difference between the 430 tonnes emitted and the 370 tonnes/GWh OBPS benchmark) x $40/tonne. That same plant would pay excess emission charges of $500 per MWh in 2022, being the difference between its emission (430 tonnes/GWh) and the EPS benchmark of 420 tonnes/GWh, times the 2022 charge of $50/tonne. Less efficient gas-fired plants will pay more. More efficient plants would not incur carbon emissions costs, and would in fact be able to trade excess emissions performance units credits to other, less efficient plants.

3.3.2 Natural Gas Price Forecast

Natural gas price assumptions are presented in Table 5 below. The forecast average Dawn/Union hub natural gas market price for the forecast period is C$5.10/MMBtu, and the forecast effective price, including the impact of excess emissions charges, is also C$5.10/MMBtu.[10]

[10] The effective price assumes a heat rate of 8 MMBtu/MWh (typical for a combined cycle plant including starts) and an emissions factor of 52 kg of CO_2e per MMBtu of natural gas. The average emissions of this plant (416 kg/MWh) is more than the OBPS performance standard but less than the EPS performance standard, meaning that this plant would need to purchase emission credits in 2021, but would be able to trade emission credits to other plants in 2022 and 2023.

Table 5: Natural Gas and GHG Allowance Price Forecasts

Month	Forward Price @ Dawn Hub US$/MMBtu	Forward Price @ Dawn Hub C$/MMBtu	OBPS/EPS Performance Standard tonnes/GWh	Excess Emission Charges C$/tonne	Effective Gas Price C$/MMBtu
Nov 2021	$5.00	$6.28	370	$40.00	$6.51
Dec 2021	$5.14	$6.46	370	$40.00	$6.69
Jan 2022	$5.23	$6.57	420	$50.00	$6.55
Feb 2022	$5.29	$6.65	420	$50.00	$6.63
Mar 2022	$5.01	$6.32	420	$50.00	$6.29
Apr 2022	$3.69	$4.67	420	$50.00	$4.64
May 2022	$3.53	$4.46	420	$50.00	$4.43
Jun 2022	$3.55	$4.47	420	$50.00	$4.45
Jul 2022	$3.57	$4.50	420	$50.00	$4.47
Aug 2022	$3.56	$4.48	420	$50.00	$4.45
Sep 2022	$3.54	$4.46	420	$50.00	$4.44
Oct 2022	$3.55	$4.48	420	$50.00	$4.45
Nov 2022	$3.72	$4.69	420	$50.00	$4.66
Dec 2022	$3.89	$4.90	420	$50.00	$4.88
Jan 2023	$3.96	$4.99	420	$65.00	$4.96
Feb 2023	$3.98	$5.01	420	$65.00	$4.98
Mar 2023	$3.72	$4.69	420	$65.00	$4.65
Apr 2023	$2.94	$3.70	420	$65.00	$3.67
Average	$4.05	$5.10	414	$52.18	$5.10

Source: Natural Gas Intelligence, Power Advisory

4. REVIEW OF FORECAST RESULTS

The results of Power Advisory's base case market price forecast are shown in Table 6. Consistent with previous editions of this report to the OEB, these prices are presented as simple averages, with high-demand and low-demand hours having equal weight.

Ontario electricity prices typically show a distinct seasonal pattern (higher in summer and winter, lower in spring and fall) which reflects natural gas prices, Ontario's load shape, typical hydroelectric generation output profiles, and the timing of maintenance outages. Natural gas prices tend to be higher in winter because of heating demand. Electricity demand in Ontario tends to be higher in summer (due to air conditioning) and in winter (due to heating) than in spring and fall. Hydroelectric generation tends to be highest in May and June due to the downstream effects of snowmelt (called the spring freshet). Maintenance outages, particularly at nuclear and gas generation facilities, are most often scheduled in the shoulder seasons. The effect of these planned outages is to mitigate the downward price impact of reduced load in the shoulder seasons and increased hydroelectric generation in the spring.

The forecast prices depart from this pattern, in that the highest quarterly average prices occur from February to April of both 2022 and 2023. This is due to the scheduled shut-downs for refurbishment of Unit 1 of the Darlington Nuclear Generating Station in the first quarter of 2022, and Unit 3 of the Bruce Nuclear Generating Station in the first quarter of 2023.

Table 6: HOEP Forecast (C$/MWh)

Calendar Period	On-Peak	Off-Peak	Average
Nov 2021 - Jan 2022	$43.09	$25.63	$33.61
Feb 2022 - Apr 2022	$43.43	$31.87	$37.13
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Source: Power Advisory

Notes: 1) Assumes natural gas prices that reflect an average of the exchange rate forecasts of five major Canadian banks (Bank of Montreal, Canadian Imperial Bank of Commerce, Royal Bank, Scotiabank, and Toronto-Dominion) as reported in their public economic forecasts as of September 29, 2021. For the November 2021 to April 2023 HOEP forecast period, the average exchange rate is US$1 = C$1.26.

2) On-peak hours are between 7 a.m. and 11 p.m. Eastern Standard Time (EST) on non-holiday weekdays. Off-peak hours are all other hours (weekends, holidays, and overnight). The times for the calculation of on-peak and off-peak hours are not adjusted for Daylight Savings Time (DST).

Power Advisory's forecast is based on a set of assumptions related to supply and demand that have been derived from best available information. Although Power Advisory has taken great care to ensure the forecast methodology is sound, by their nature forecasts are uncertain and cannot be guaranteed.