


Ontario Wholesale Electricity Market Price Forecast

For the Period November 1, 2025 through April 30, 2027

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, 2025 to April 30, 2027 period. This wholesale electricity price forecast is one input that will be used by the OEB to set the Regulated Price Plan (RPP) prices for eligible consumers under the *Ontario Energy Board Act, 1998*.

Power Advisory has relied on a complex model of Ontario's electricity market to forecast the Ontario Electricity Market Price (OEMP), which has replaced the previous Hourly Ontario Energy Price (HOEP) as part of the Independent Electricity System Operator's (IESO) Market Renewal Program (MRP) that was implemented on May 1. The updated design of the wholesale market that resulted from MRP is referred to as the "renewed market" for the remainder of this report. The model used to forecast prices 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 — recognizing that price formation in the renewed market is structurally different than the legacy wholesale market (as discussed later in this report). Amongst other data, the model incorporates Ontario's electricity demand and hourly load shape, new committed supply, planned generation retirements, operating profiles of Ontario's hydroelectric generation (including both baseload and peaking resources), operating characteristics of Ontario's thermal generation, and expected fuel and carbon prices. Many of these assumptions and variables will interact with one another on a 5-minute and hourly basis, creating significant complexity when forecasting future 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: OEMP Forecast (C$ per MWh)

Calendar Period	On-Peak	Off-Peak	Average
Nov 2025 - Jan 2026	$66.22	$45.89	$55.13
Feb 2026 - Apr 2026	$63.45	$47.43	$54.85
May 2026 - Jul 2026	$55.62	$30.69	$42.17
Aug 2026 - Oct 2026	$73.20	$50.04	$60.55
Nov 2026 - Jan 2027	$108.83	$82.54	$94.53
Feb 2027 - Apr 2027	$97.06	$77.29	$86.46
Nov 2025 - Apr 2027	$77.37	$55.57	$65.56

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 8, 2025. For the November 2025 to April 2027 OEMP forecast period, the average exchange rate is US$1 = C$1.32.

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, 2025 to April 30, 2027 period (forecast period). This wholesale electricity price forecast is one input used by the OEB to set November 1, 2025 Regulated Price Plan (RPP) prices for eligible consumers under the *Ontario Energy Board Act, 1998*. Wholesale electricity prices will 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 (GA).

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 electricity prices in Ontario are determined by the Independent Electricity System Operator (IESO) based on provincial electricity demand and the amounts paid to generators to supply it. Generators supplying electricity to the Ontario wholesale market must offer their supply to the IESO in 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 and dispatchable demand resources to meet forecasted demand in each five-minute interval of each hour. The selection of resources based on cost will also incorporate physical constraints, such as generation ramp rates, transmission constraints, and other physical limitations.

On May 1, the IESO implemented its MRP, which significantly updated the design of the IESO-Administered Market (IAM or "wholesale market"). The most notable changes to the renewed market that will impact the price forecast used in the RPP rate-setting process include (but are not limited to):

1. *Locational prices*: Under the legacy market, the wholesale price was determined on what was known as an "unconstrained" basis. This meant that it did not include any of the physical constraints on the transmission network or from specific generators. Instead, it determined the price assuming all supply – no matter where it was located on the transmission grid – could be used to meet demand. It also assumed that suppliers could "ramp" up or down faster than their actual physical capabilities. Given the lack of transmission constraints included in the price-setting process, it determined a single, province-wide price that would be paid by all consumers. Any divergences between the physical capability of the transmission network or specific generators were dealt with through out-of-market payments that did not impact the province-wide wholesale price. In the renewed market, the dispatch algorithm now includes transmission constraints and physical attributes of each generator and sets price accordingly. This results in what are known as Locational Marginal Prices (LMPs) that can be different at the many – nearly 1,000 – different nodes across the transmission network. Overall, price formation in the new market is now structurally different than in the legacy market, as it is no longer determined on an "unconstrained" basis.

2. *Financially Binding Day-Ahead Market (DAM):* The new market also includes what is known as a financially binding DAM. This means that market participants – both generators and some large consumers – will provide offers and bids the day before real-time. The DAM calculation engine then provides the schedule and prices that market participants are financially bound to follow. If the suppliers – or dispatchable loads – diverge from their day-ahead schedules in real-time, they will face a settlement charge, which can be positive or negative depending on real-time prices compared to day-ahead prices and their real-time output compared to their day-ahead schedule. The legacy market did not include a financially binding DAM. The DAM prices are the primary wholesale price used in the RPP forecast.

3. *Enhanced commitment programs for gas-fired generators:* The renewed market also included a number of changes to the commitment programs that were designed for gas-fired generators. The new commitment programs are intended to be more economically efficient in terms of both settlement and commitment. Overall, the programs are expected to lower overall costs and commit units more efficiently, which will impact wholesale prices.

The renewed market is still in the early stage of operation. As such, there is uncertainty in how wholesale prices will evolve over time and how they will compare to historical prices. While the marginal cost of energy – which is the primary factor in determining wholesale prices – remains the key factor in the wholesale market, the new pricing, dispatch, and day-ahead features of the renewed market may result in different dispatch and pricing outcomes than the legacy market.

In both the legacy and renewed market, the interaction of hourly supply and demand was and will continue to be the primary determinant of Ontario's wholesale electricity market price. As noted previously, setting prices under the renewed market is now a two-step process. First, hourly forecasts of supply and demand are balanced in the DAM. These prices take losses and transmission constraints into account, resulting in different LMPs across the wholesale market. A load-weighted average (using only non-dispatchable loads) of LMPs is calculated, called the Day-Ahead Ontario Zonal Price (DA-OZP).

Second, supply and demand are balanced in the Real-Time Market for each five-minute interval. The cost impact of differences between the Day-Ahead load forecast and actual energy consumption of non-dispatchable loads is recovered through the hourly Load Forecast Deviation Adjustment (LFDA). The sum of the DA-OZP and the LFDA is called the Ontario Electricity Market Price (OEMP); this is the hourly price paid by RPP customers and most other consumers in Ontario.

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 OEMP 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 – recognizing that under the renewed market, pricing formation is different. Nonetheless, the primary connection between demand and the resources – including their marginal cost – used to meet that demand have not changed. 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, particularly with the wide-ranging and structural changes included in the renewed market. Recognizing that the underlying marginal costs of suppliers participating in the IAM remain broadly the same, the starting point for Power Advisory's model is hourly prices – which underpinned historical wholesale prices – over the past five years (2020-2024). For each forecast year, the model takes the hourly prices for the first historical base year (2020), 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, nuclear supply will be reduced, and wholesale 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 wholesale prices in hours which experienced greater wind in the base year. The relationship between supply, demand, and wholesale price is established through regression analysis as part of the modelling process. Prices are 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 (2021, 2022, 2023 and 2024), 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 Pickering B, 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 wholesale electricity prices) 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.
- Locational Prices: As noted above, transmission constraints and losses are now included in energy prices at different points on the grid. These locational differences will impact the DA-OZP that is used in the RPP forecast, as it is a load-weighted average of all LMPs.

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

3. KEY FORECAST ASSUMPTIONS

The major assumptions used in the OEMP 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 2025 to March 2027* (released September 18, 2025) (*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. For the October 2025 through March 2026 period, the demand forecast in the current *Reliability Outlook* (dated September 18, 2025) overlaps with that in the Reliability Outlook published in September 2024 that informed November 1, 2024 RPP prices. For the five months of overlap (November 2025 – March 2026), the new (September 2025) forecast is on average 0.9% lower than the older (September 2024) forecast. However, for the two forecast periods (November 2024 – March 2026, vs. November 2025 – March 2027), the September 2025 Reliability Outlook forecasts 2.5% higher demand than the September 2024 Reliability Outlook.

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 OEMP forecast model takes into account both grid-level demand and the demand supplied by embedded generation.

The forecast period for this report (November 1, 2025 - April 30, 2027) 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.

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[2] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2025Sep.pdf

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 2025	11.59	0.49	12.08	20,192
Dec 2025	12.93	0.45	13.38	21,485
Jan 2026	13.92	0.47	14.39	22,860
Feb 2026	12.30	0.48	12.79	21,865
Mar 2026	12.70	0.56	13.26	20,637
Apr 2026	11.18	0.69	11.87	18,618
May 2026	11.29	0.67	11.95	19,765
Jun 2026	11.98	0.68	12.66	23,157
Jul 2026	13.27	0.63	13.90	24,246
Aug 2026	12.92	0.60	13.53	23,485
Sep 2026	11.60	0.54	12.14	22,002
Oct 2026	11.61	0.53	12.14	19,080
Nov 2026	12.15	0.49	12.64	21,203
Dec 2026	13.42	0.45	13.88	22,082
Jan 2027	14.00	0.47	14.47	22,852
Feb 2027	12.36	0.48	12.84	21,996
Mar 2027	12.72	0.56	13.28	20,734
Apr 2027	11.43	0.69	12.13	18,997
Total/Maximum	223.38	9.96	233.33	24,246

Source: IESO, Reliability Outlook (September 18, 2025), Table 3.1.1 Planned; Power Advisory

3.2 Supply Resources

Power Advisory's generation capacity assumptions are generally 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 Non-Nuclear Generation Capacity Additions

In addition to the existing supply resources, 1,475 MW of new capacity is expected to come into service during the forecast horizon, as shown in Table 2. 40% of this is gas capacity at existing sites, and 60% is storage. These additions have been included in the model specification.

Table 2: Major Non-Nuclear Generation Capacity Changes

Project Name	Resource Type	Planned Capacity (MW)	Estimated Effective Date
Gas Upgrades STU	Gas	180	2025-Q3 to Q4
Gas Upgrades STU	Gas	75	2025-Q2 to Q3
Brighton Beach Upgrade	Gas	43	2025-Q3
Expedited – Long Term 1 Projects	Various	176	2025-Q2 to Q3
Expedited – Long Term 1 Projects	Various	1001	2026-Q2

Source: IESO, Reliability Outlook (September 18, 2025), Table 4.2.

The IESO is not forecasting any changes in distribution-connected generation capacity during the forecast period, other than some of the storage capacity included in Table 2.[3] However, Power Advisory is forecasting small increases in behind-the-meter solar generation, not under contract with the IESO. Including distribution-connected generation, the model assumes that a total of 2,800 MW of solar capacity and 5,500 MW of wind capacity will be in service by April 2027, capable of generating enough electricity to meet approximately 13% of Ontario's demand. Solar and wind generation put downward pressure on Ontario's wholesale electricity prices.

3.2.2 Nuclear Capacity

There are currently three nuclear units out of service for refurbishment: Bruce A Unit 3, Bruce A Unit 4, and Darlington Unit 4. Both Bruce 3 and Darlington 4 are scheduled to return to service during the forecast horizon. According to the 2025 *Annual Planning Outlook*[4], their expected return dates are in December 2026 and July 2026 respectively. However, other nuclear units have returned to service from refurbishment earlier than scheduled, and there are indications that these two units will as well. Power Advisory's model assumes that both will return at the beginning of May 2026. Bruce 4 is expected to remain out of service for the entire forecast period.

Five units are expected to shut down for refurbishment during the forecast horizon, all at the end of September, 2026: the four remaining Pickering units (5 – 8), and Bruce B Unit 5.

The September 2025 *Reliability Outlook* contains forecasts of total nuclear generation in each month in its forecast period (October 2025 – March 2027), consistent with the nuclear

[3] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlookTables_2025Sep.ashx, Table 3.4.5.

[4] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2025/2025-Annual-Planning-Outlook.pdf, Figure 11.

refurbishment dates in the IESO's *2025 Annual Planning Outlook* Report[5] (i.e., with Darlington 4 returning in July 2026 and Bruce 3 returning in December 2026). Power Advisory's model was calibrated to assume the same monthly generation volumes, plus additional generation in May – December 2026 to reflect the modelled early return of these two units. For the one month outside of the Reliability Outlook's study period, (April 2027), nuclear generation was based on historical patterns. Based on these assumptions, the OEMP forecast model assumes total nuclear generation of 110.53 TWh over the forecast period, as shown in Table 3 below. This implies a capacity factor of 89.0%, 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 for refurbishment. It takes into account expected curtailment of some of the Bruce units during times when domestic supply exceeds demand, if necessary. The nuclear fleet shows 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 2025	6.32
Dec 2025	6.95
Jan 2026	6.82
Feb 2026	5.88
Mar 2026	6.64
Apr 2026	5.91
May 2026	7.14
Jun 2026	7.29
Jul 2026	7.44
Aug 2026	7.33
Sep 2026	7.14
Oct 2026	4.86
Nov 2026	5.06
Dec 2026	5.57
Jan 2027	5.25
Feb 2027	4.51
Mar 2027	5.35
Apr 2027	5.09
Total	110.53

Source: Power Advisory

[5] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2025/2025-Annual-Planning-Outlook.pdf, Figure 11, p. 33.

3.2.3 Hydroelectric 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 OEMP forecast model is historical supply and demand for the five base years (2020-2024). During these years, annual output of transmission-connected hydro ranged from a low of 33.7 TWh in 2021 to a high of 37.5 TWh in 2022. This range is reflected in the forecast, which is based on an average of the forecasts 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 63 MW of distribution-connected hydroelectric capacity between January 2020 and January 2023).

3.2.4 Transmission Capabilities and Constraints

Since the implementation of the MRP on May 1, 2025, Ontario's wholesale electricity market has had different electricity prices in different parts of the province. The focus of Power Advisory's model is on forecasting the OEMP – the uniform price paid by most electricity consumers throughout the province – so it reflects transmission constraints within Ontario to the greatest extent possible through statistical adjustments, although a new locational-based model has been used to compare pricing results.

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	246	300	260	300
Minnesota	150	150	100	100
Michigan	1,650	1,650	1,550	1,700
New York	1,800	2,100	1,500	1,900
Québec	2,145	2,165	2,330	2,350

Source: IESO, Reliability Outlook (September 18, 2025), 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 hub in Southwestern Ontario. While trade volumes at this hub are lower, and therefore less widely reported than at other gas hubs, S&P Global Intelligence reports forward prices for up to thirteen years into the future. 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 21 days (August 16 – September 5, 2025) 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 $1.32 CAD per USD between November 2025 and April 2027. 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 8, 2025. 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 OEMP forecast factors in 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. As of January 1, 2022, the province has fully transitioned from the OBPS to the EPS.[7] The EPS system is quite similar to the OBPS system, including identical charges for excess emissions: $95 per tonne of carbon dioxide equivalent (CO_2e) emitted in 2025, $110 per tonne in 2026, and $125 per tonne in 2027. One difference is in the benchmark above which excess emission charges would need to be paid: 206 tonnes/GWh in the federal OBPS in 2025, falling to 123 tonnes/GWh in

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

[7] https://www.ontario.ca/page/emissions-performance-standards-program

2027,[8] compared to 310 tonnes/GWh in all three years in Ontario's EPS.[9] Generators in Ontario are assumed to be subject to the 310 tonnes/GWh benchmark throughout the forecast period (November 2025 through April 2027).

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.

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 $11,400 in excess emissions charges in 2025. The $11,400 charge is determined based on CO_2e emissions of 120 tonnes (being the difference between the 430 tonnes emitted and the 310 tonnes/GWh EPX benchmark) x $95/tonne, the excess emissions charge in 2025. That same plant would pay excess emission charges of $13,200 per MWh in 2026 and $15,000 in 2027, based on the same volume of excess emissions (120 tonnes), but with charges increasing to $110/tonne and $125/tonne in 2026 and 2027 respectively. Less efficient gas-fired plants will pay more.

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$4.70/MMBtu, and the forecast effective price, including the impact of excess emissions charges, is C$6.18/MMBtu.[10]

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[8] https://gazette.gc.ca/rp-pr/p2/2019/2019-07-10/html/sor-dors266-eng.html

[9] Ontario Ministry of the Environment, Conservation and Parks, GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit, December 2022 (https://prod-environmental-registry.s3.amazonaws.com/2022-12/GHG%20EPS%20and%20Methodology%20for%20determination%20of%20TAEL_December%202022%20(EN).pdf)

[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. This heat rate corresponds to an emissions average of 416 tonnes/GWh.

Table 5: Natural Gas and GHG Allowance Price Forecasts

Month	Forward Price @ Dawn Hub US$/MMBtu	Forward Price @ Dawn Hub C$/MMBtu	Emissions Performance Standard tonnes/GWh	Excess Emission Charges C$/tonne	Effective Gas Price C$/MMBtu
Nov 2025	$3.07	$4.17	310	$95.00	$5.43
Dec 2025	$3.58	$4.85	310	$95.00	$6.11
Jan 2026	$3.70	$4.97	310	$110.00	$6.43
Feb 2026	$3.84	$5.13	310	$110.00	$6.59
Mar 2026	$3.59	$4.83	310	$110.00	$6.29
Apr 2026	$3.19	$4.22	310	$110.00	$5.67
May 2026	$3.14	$4.14	310	$110.00	$5.59
Jun 2026	$3.21	$4.30	310	$110.00	$5.76
Jul 2026	$3.36	$4.38	310	$110.00	$5.83
Aug 2026	$3.40	$4.41	310	$110.00	$5.86
Sep 2026	$3.37	$4.46	310	$110.00	$5.92
Oct 2026	$3.41	$4.38	310	$110.00	$5.84
Nov 2026	$3.75	$4.78	310	$110.00	$6.24
Dec 2026	$4.06	$5.34	310	$110.00	$6.80
Jan 2027	$4.16	$5.40	310	$125.00	$7.06
Feb 2027	$4.32	$5.61	310	$125.00	$7.27
Mar 2027	$4.03	$5.24	310	$125.00	$6.90
Apr 2027	$3.12	$4.05	310	$125.00	$5.71
Average	$3.57	$4.70	310	$111.62	$6.18

Source: S&P Global 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 broadly follow this pattern, in that the prices start higher in November 2025 – February 2026, fall to their lowest point in May – July 2026, then rise again. However, the main driver of wholesale prices in this forecast is nuclear generation: forecast wholesale prices fall in May 2026 because two nuclear units (Bruce 3 and Darlington 4) are assumed to return to service at the beginning of May, and wholesale prices rise sharply in October 2026 because five nuclear units are assumed to go out of service for refurbishment at the end of September.

As noted previously, price formation in the renewed market is structurally different than the legacy market. Given that there is no historical data for a winter season – when prices and demand are more volatile – under the renewed market design, a higher amount of forecast uncertainty can be expected. Looking back at the summer of 2025, wholesale prices in some months were much higher than historical averages. Breaking out the price impact of the new market design compared to broader changes (i.e. higher demand and gas prices) is challenging given the limited timeframe and data from the renewed market. As such, significant uncertainty in future prices remains.

Table 6: OEMP Forecast (C$/MWh)

Calendar Period	On-Peak	Off-Peak	Average
Nov 2025 - Jan 2026	$66.22	$45.89	$55.13
Feb 2026 - Apr 2026	$63.45	$47.43	$54.85
May 2026 - Jul 2026	$55.62	$30.69	$42.17
Aug 2026 - Oct 2026	$73.20	$50.04	$60.55
Nov 2026 - Jan 2027	$108.83	$82.54	$94.53
Feb 2027 - Apr 2027	$97.06	$77.29	$86.46
Nov 2025 - Apr 2027	$77.37	$55.57	$65.56

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 8, 2025. For the November 2025 to April 2027 OEMP forecast period, the average exchange rate is US$1 = C$1.32.

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.