



Ontario Wholesale Electricity Market Price Forecast

For the Period November 1, 2026 through October 31,
2027

Prepared for: Ontario Energy Board
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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, 2026 to October 31, 2027 period. The wholesale electricity price forecast is one of the key inputs used by the OEB to set the Regulated Price Plan (RPP) prices for eligible consumers under the *Ontario Energy Board Act, 1998*.

Power Advisory used a zonal market simulation model to forecast the Ontario Electricity Market Price (OEMP). The OEMP replaced the previous Hourly Ontario Energy Price (HOEP) as part of the Independent Electricity System Operator's (IESO) Market Renewal Program (MRP), which was fully implemented on May 1, 2025. 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 is developed with the industry-standard PLEXOS software. Power Advisory's forecast model – as described in more detail later in this report – incorporates hourly economic dispatch of all market participants in the IESO-Administered Market (IAM), as well as known transmission constraints, generator unit commitment, and other physical parameters that impact Locational Marginal Prices (LMPs) at different zones on the grid.

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

Table ES-1: OEMP Forecast (\$/MWh)

Month	On-Peak	Off-Peak	Average
Nov 2026	\$50.42	\$44.83	\$47.47
Dec 2026	\$64.03	\$55.54	\$59.61
Jan 2027	\$123.92	\$98.81	\$110.28
Feb 2027	\$104.75	\$90.19	\$97.19
Mar 2027	\$58.69	\$49.37	\$53.84
Apr 2027	\$85.19	\$66.45	\$76.18
May 2027	\$54.89	\$48.61	\$51.48
Jun 2027	\$62.94	\$47.74	\$55.64
Jul 2027	\$100.65	\$63.49	\$81.32
Aug 2027	\$89.88	\$61.31	\$75.02
Sep 2027	\$64.06	\$59.94	\$61.89
Oct 2027	\$48.24	\$44.43	\$46.17
Nov 2026 - Oct 2027	\$75.51	\$60.72	\$67.85

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 3 2026. For the November 2026 to October 2027 OEMP forecast period, the average exchange rate is US\$1 = C\$1.36.

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 Saving Time (DST).

3) All dollar figures are in Canadian dollars unless otherwise stated.

TABLE OF CONTENTS

1. INTRODUCTION.....	1
1.1 Contents of This Report.....	2
2. PRICE FORECASTING METHODOLOGY.....	3
2.1 Overview of Ontario's Wholesale Electricity Market.....	3
2.2 Overview of the Forecasting Model.....	4
2.3 Key Forecast Drivers.....	5
2.4 Key Forecast Assumptions.....	6
2.4.1 Demand Forecast.....	6
2.4.2 Supply Resources.....	8
2.4.3 Transmission Capabilities and Constraints.....	9
2.4.4 Natural Gas Prices.....	11
2.4.5 GHG Emission Allowance Price Forecast.....	11
2.4.6 Effective Natural Gas Price Forecast.....	12
3. REVIEW OF FORECAST RESULTS.....	14

LIST OF TABLES

Table 1: Forecast Monthly Energy Consumption and Peak Demand.....	7
Table 2: Major Generation Capacity Changes.....	8
Table 3: Forecast Nuclear Generation.....	9
Table 4: Ontario Interconnection Limits.....	11
Table 5: Natural Gas and GHG Allowance Price Forecasts.....	13
Table 6: OEMP Forecast (\$/MWh).....	15

LIST OF FIGURES

Figure 1: Average Historical Congestion Price (\$/MWh).....	10
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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, 2026 to October 31, 2027 period (forecast period). This wholesale electricity price forecast is one of the key inputs used by the OEB to set November 1, 2026 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 (GA). The combination of wholesale prices and GA payments accounts for the majority of the total supply cost for RPP customers. The combination of wholesale prices and GA charges are the primary components of what is known as the “hybrid” structure of Ontario’s electricity market.

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 three chapters, starting with this introduction. Chapter 2 outlines the price forecasting methodology, identifies the key forecast drivers and provides an overview of the forecast assumptions and information sources on which these assumptions are based. Chapter 3 presents the Ontario wholesale electricity market price forecast results.

2. PRICE FORECASTING METHODOLOGY

2.1 Overview of Ontario's Wholesale Electricity Market

Hourly and 5-minute wholesale electricity prices in Ontario are published by the IESO and are 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.

Since the renewed market was launched on May 1, 2025, the Ontario wholesale market now includes a financially binding Day-Ahead Market (DAM) and real-time balancing market, among other changes. The DAM is the primary source of supply costs for RPP customers, as this is where most supply is procured to serve domestic load (i.e., the combination of RPP customers and other customer classes). Based on offers from suppliers and bids from Dispatchable Loads, the IESO uses a dispatch algorithm to choose the least-cost combination of electricity resources to meet forecasted demand in each hour of the DAM and 5-minute interval in real-time. The selection of resources – and pricing outcomes in the IAM – now incorporates factors such as generation ramp rates, transmission constraints, and other physical limitations. Many of these components – particularly transmission congestion – now play a more prominent role in hourly prices in the renewed market compared to the legacy market that used out-of-market payments to account for physical and other limitations to dispatch.¹

The changes in the renewed market that most 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 serve 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 “unconstrained” generator dispatch and 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 specifically includes transmission constraints and physical attributes of each generator and sets prices accordingly. This results in what are known as Locational Marginal Prices (LMPs) that can differ at each of the nearly 1,000 nodes across the transmission network. LMPs are averaged on a load-weighted basis to determine the Ontario Zonal Price (OZP), which is applied to RPP customers through the OEMP.

¹ See the Market Surveillance Panel's report for a detailed review of out-of-market payments in the legacy IAM: https://www.oeb.ca/oeb/Documents/MSP/MSP_CMSC_Report_201612.pdf

2. ***Financially Binding Day-Ahead Market (DAM):*** The new market 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 in real-time. 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, as the real-time market predominantly acts as a balancing market to account for load forecast error or other differences between the DAM and real-time.
3. ***Enhanced commitment programs for gas-fired generators:*** The renewed market also included a number of changes to the commitment programs that were predominantly designed for gas-fired generators. The new commitment programs are intended to be more economically efficient in terms of both settlement and commitment. The programs are expected to lower overall costs and commit units more efficiently, which will impact wholesale prices.

The renewed market has now been in operation for more than a year. While the Ontario market is facing an evolution in the underlying supply and demand components – discussed in more detail later in this report – there are a number of pricing trends and outcomes in the renewed market that appear to be structural rather than temporary. These features – notably as they relate to known and ongoing transmission constraints that will impact LMPs – have been incorporated into the wholesale market model and forecast. Nonetheless, as noted in previous reports, the interaction of hourly supply and demand continues to be the primary determinant of Ontario's wholesale electricity market price and both of these variables will diverge from the forecast at times.

The primary difference in the renewed market is that prices now take physical 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). 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 make up the OEMP; this is the hourly wholesale price paid by RPP customers and most other non-dispatchable 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. The model is calibrated to the historical relationship between these drivers and Ontario market outcomes. While price

formation has changed under the renewed market, the underlying relationship between demand and the marginal cost of the resources used to meet it has not.

Power Advisory's wholesale market forecast relies on the industry-standard PLEXOS software, which can incorporate the physical constraints of the transmission systems as well as physical limitations of individual units. The model includes both a marginal cost and (where appropriate) fixed start-up costs for each supplier in Ontario and then dispatches units based on system-wide cost optimization to balance supply and demand. The model also incorporates the interties that Ontario has with neighbouring jurisdictions and will commit imports or exports on an economic arbitrage basis (i.e., exporting when Ontario prices are lower than in neighbouring markets and importing when they are higher). Hourly Ontario demand and output from wind, solar, and hydroelectric generation is shaped using historical weather patterns – meaning it will vary on both an hourly and seasonal basis.

To account for the changes in the renewed market, some physical constraints of the grid are included in the dispatch outcomes. For example, there is often a limitation on the transmission network in flowing energy from northern Ontario to the major load centres in southern Ontario. When this occurs, the lowest cost resources from the north will be committed first until the transmission interface is operating at its maximum capacity. Any remaining low-cost generation in the congested region will not be committed – and conversely, higher marginal cost resources may be committed and dispatched on the other side of the transmission interface to serve load. The result of this dynamic from a pricing perspective is what is known as congestion pricing, with the LMPs that are in the congested region being lower than LMPs on the other side of the transmission constraint. As noted previously, the legacy market did not incorporate congestion into wholesale prices.

2.3 Key Forecast Drivers

Although other influences exist, forecast price changes are driven primarily by a few 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. For example, peak demand in Ontario typically occurs in the late afternoon and early evening in the summer months of July and August. When peak demand occurs, the most expensive units from a marginal cost perspective will set price and the wholesale price will be higher than the monthly or annual average. Conversely, in what are known as “shoulder” months in the fall and spring, demand is below average and the wholesale price is also typically below the monthly and annual average. Power Advisory relies on the IESO’s Reliability Outlook to forecast total demand over the upcoming RPP period.
- **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 and Bruce nuclear plants. Nuclear supply, in particular, will have a substantial impact on wholesale market prices in the upcoming RPP period. The total amount of nuclear supply in the upcoming RPP is forecasted to be much lower than historical levels in Ontario given the refurbishment of the Pickering B station, ongoing refurbishments at the Bruce Nuclear Generating Station

and a number of planned outages at the Darlington Nuclear Generating Station in 2027. When baseload nuclear units are removed from the supply stack, higher marginal cost resources are needed to service demand – pushing wholesale prices higher.

- **Cost of generation from 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. Historically, gas-fired generation in Ontario was largely used as a “peaking” resource and dispatched during hours/days of elevated demand. More recently – and in particular in the upcoming RPP period – gas-fired generation is being committed and dispatched more frequently. This impacts prices in two ways: first, it means gas-fired generation will be the price-setting unit in more hours and second, the less efficient (i.e., higher marginal cost) resources will set price more often. Both of these factors put upward pressure on wholesale prices.
- **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. With the renewed market having been in operation for more than a year, there are now a few well-known transmission constraints that frequently impact LMPs.

2.4 Key Forecast Assumptions

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

2.4.1 Demand Forecast

The basis for Power Advisory’s energy demand forecast is the IESO’s Q3 2026 *Reliability Outlook* covering the period from October 2026 to March 2028 (released September 17, 2026) (*Reliability Outlook*).² The IESO’s forecast takes conservation and demand management programs into account. It assumes “normal weather” – i.e., daily weather conditions that are typical for that time of year. For the October 2026 through March 2027 period, the demand forecast in the current *Reliability Outlook* overlaps with that in the *Reliability Outlook* published in October 2025 that informed November 1, 2025 RPP prices. For the five overlapping months that fall within this forecast period (November 2026 – March 2027), the September 2026 forecast is on average 0.7% lower than the October 2025 forecast. However, forecast demand for the

² <https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2026Sep.xlsx>

November 2026 – October 2027 period is 0.5% higher than the forecast used for the November 2025 – October 2026 period. This continues the upward trend in Ontario electricity demand that followed nearly a decade of flat, transmission-connected load growth from 2010 to 2020.

The IESO forecasts demand at the transmission grid level. Ontario has a significant supply of generation “embedded” in the distribution network, which supplies a corresponding volume of consumer demand that does not pass through the transmission system. The IESO accounts for embedded generation in its forecast of grid-level demand. Like the *Reliability Outlook*, Power Advisory’s OEMP forecast model considers demand at the transmission grid level.

The forecast period for this report (November 1, 2026 - October 31, 2027) is covered by the IESO’s *Reliability Outlook*. Table 1 shows the forecast of monthly energy consumption and peak demand used in the model.

Table 1: Forecast Monthly Energy Consumption and Peak Demand

Month	Grid-Level Demand (TWh)	Embedded Generation (TWh)	Total Demand (TWh)	Peak Grid Demand (MW)
Nov 2026	11.93	0.52	12.45	20,892
Dec 2026	13.24	0.45	13.69	21,894
Jan 2027	13.81	0.55	14.36	22,834
Feb 2027	12.25	0.46	12.71	21,946
Mar 2027	12.58	0.68	13.26	20,659
Apr 2027	11.14	0.72	11.86	18,652
May 2027	11.15	0.79	11.94	19,895
Jun 2027	11.81	0.72	12.52	23,036
Jul 2027	12.94	0.68	13.62	24,036
Aug 2027	12.89	0.60	13.48	23,481
Sep 2027	11.61	0.56	12.16	22,058
Oct 2027	11.68	0.60	12.28	19,344
Total/Maximum	147.00	7.32	154.32	24,036

Source: IESO, *Reliability Outlook* (September 17, 2026), Table 1.1.1 Firm; IESO, *2026 Annual Planning Outlook* (March 20, 2026), Table 5; Power Advisory

2.4.2 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.

2.4.2.1 Generation Capacity Additions

In addition to the existing supply resources, 888 MW of capacity is expected to come into service during the forecast horizon while 2,925 MW of capacity from nuclear is expected to come offline, as shown in Table 2. Power Advisory captured new resources online from the Expedited Long-Term 1 (E-LTI) procurement and upgrades to Sir Adam Beck Generating Station. These additions have been included in the model specification.

Table 2: Major Generation Capacity Changes

Project Name	Resource Type	Capacity (MW)	Estimated Effective Date
Pickering G5	Nuclear	-525	2026-Q4
Pickering G6	Nuclear	-525	2026-Q4
Pickering G7	Nuclear	-525	2026-Q4
Pickering G8	Nuclear	-525	2026-Q4
Bruce G5	Nuclear	-825	2026-Q4
Bruce G4	Nuclear	813	2027-Q4
Sir Adam Beck	Hydro	7	2027-Q1
E-LTI Storage	Storage	68	2027-Q2

Source: IESO, *Reliability Outlook* (September 17, 2026), Table 2.2; Power Advisory

2.4.2.2 Nuclear Capacity

Five nuclear units will be shut down for refurbishment during the forecast horizon: the four remaining Pickering units (5 – 8) that were taken offline in September 2026 and Bruce B Unit 5 in the 4th Quarter of 2026. According to the 2026 *Annual Planning Outlook*,³ the expected return date of Bruce A Unit 4 is in the end of December 2027. Based on the return-to-service of previous

³ <https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2026/2026-Annual-Planning-Outlook.pdf>, Figure 9.

units, Power Advisory assumes Bruce A Unit 4 returns to service three months earlier than expected and it is in-service during the last month of the forecast period.

Power Advisory's modelled nuclear output is based on monthly production forecasts from Bruce Power and OPG, plus additional generation starting in October 2027 to reflect the assumed early return of Bruce A Unit 4. Based on these assumptions, the OEMP forecast model assumes total nuclear generation of 59.39 TWh over the forecast period, as shown in Table 3. This implies a capacity factor of 77%, 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. In spring 2027, in particular, there is lower nuclear supply due to a major planned outage at the Darlington Nuclear Generating Station.

Table 3: Forecast Nuclear Generation

Month	Nuclear Generation (TWh)
Nov 2026	5.02
Dec 2026	5.38
Jan 2027	5.12
Feb 2027	4.39
Mar 2027	5.13
Apr 2027	4.07
May 2027	3.86
Jun 2027	5.24
Jul 2027	5.39
Aug 2027	5.36
Sep 2027	4.97
Oct 2027	5.46
Total	59.39

Source: Bruce Power; OPG; Power Advisory

2.4.2.3 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 OEMP forecast model is historical supply for recent years and selecting a weather year that best reflects the typical annual output of hydro generation. From 2020 to 2025, the annual output of transmission-connected hydro ranged from a low of 34.2 TWh in 2021 to a high of 38 TWh in 2022. The forecasts of hydro output are adjusted for changes in installed hydro capacity (such as upgrades in recent years to a number of units at the Sir Adam Beck Generating Station).

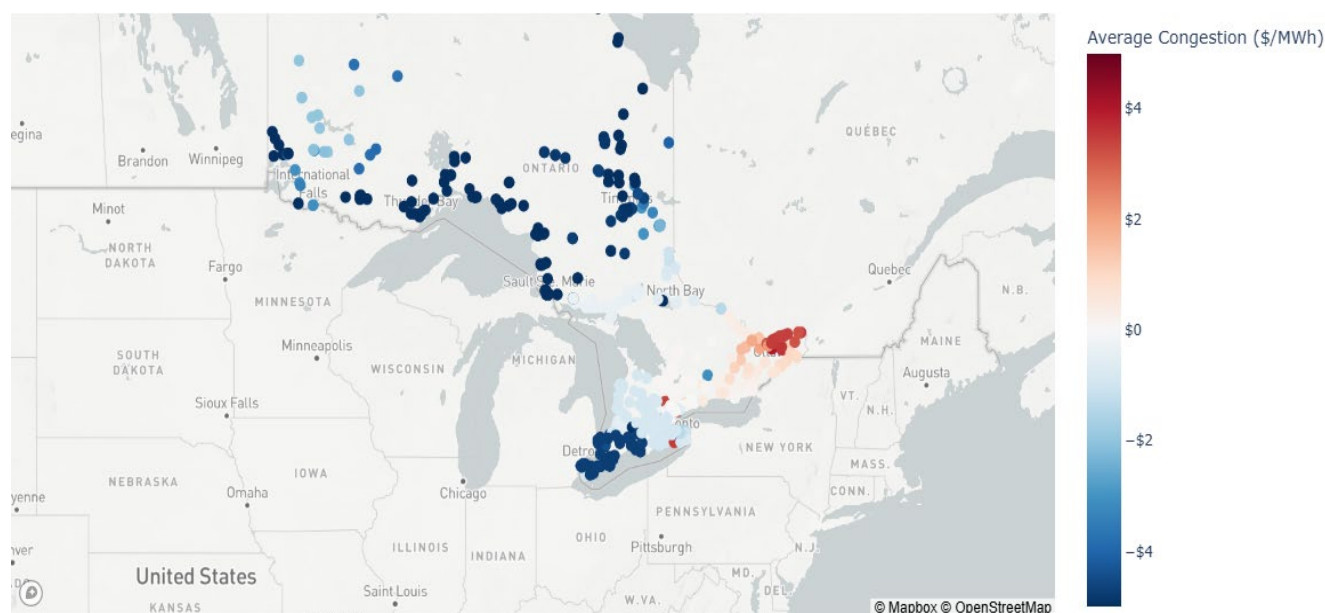
2.4.3 Transmission Capabilities and Constraints

Since the implementation of the MRP in May 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 that underpin the OEMP. Unlike the Hourly Ontario Energy Price (which was the price paid by most consumers prior to Market Renewal), the OEMP incorporates the cost of transmission losses and congestion (costs which were previously included in the Wholesale Market Service Charge). The forecast model therefore includes these costs.

As shown below, there are structural differences in prices in different regions of the wholesale market. LMPs in the Northeast and Northwest zones face significant transmission congestion in many hours and, as such, have on average lower prices. Other zones – including the Niagara and Ottawa zones – have also experienced material transmission congestion. For the Ottawa zone, congestion resulted in much higher prices in the 2025/2026 winter months as higher marginal cost resources were required to serve local demand. The graph below highlights the average congestion component for the different LMPs over the first year of the renewed market. Negative congestion will result in a lower LMP for that node compared to the reference price, while the opposite is true when there is positive congestion. As can be seen below, negative congestion was most prevalent in the Northwest and Northeast zones (and to a lesser extent in the West zone), while positive congestion occurred more often in the Ottawa zone.

Figure 1: Average Historical Congestion Price (\$/MWh)



External transfer limits can also affect Ontario energy prices. Limited import transfer capability can lead to higher wholesale prices, because less expensive imports cannot be brought in. Similarly, suppliers may be unable to sell their surplus in other markets due to export transfer limits, and this may result in lower wholesale prices in Ontario than would otherwise be the case. 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* and *Annual Planning Outlook*.

Table 4: Ontario Interconnection Limits

(MW)	Flows Out of ON	Flows Into ON
Manitoba	250	250
Michigan	1650	1500
Minnesota	150	150
New York	1835	2150
Quebec	2340	2565

Source: IESO, 2026 Annual Planning Outlook: Ontario's Transmission Interfaces and Interties (March 20, 2026), Table 1; IESO, Reliability Outlook (September 17, 2026), Table 4.3

2.4.4 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, S&P Global Intelligence reports forward prices for up to thirteen years into the future. Power Advisory used these prices in its OEMP forecast. Power Advisory adjusts monthly forward prices using a daily shape based on historical gas price volatility.

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 influence of this day-to-day volatility, Power Advisory uses the average of three forward curves observed at one-week intervals.

Forward prices are reported in US dollars and therefore must be converted into Canadian dollars. The price forecast reflects an average exchange rate of \$1.36 CAD per USD between November 2026 and October 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 3, 2026.

2.4.5 GHG Emission Allowance Price Forecast

The OEMP 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*.⁴ 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.⁵ The EPS system is quite similar to the OBPS system, including identical charges for excess emissions. On May 15, 2026, the federal government updated the pricing benchmark to the following: \$95 per tonne of carbon dioxide equivalent (CO₂e) emitted in 2026, \$100 per tonne in 2027 to 2029, and an increase to \$130 per tonne in 2035 before a 1.5% per year inflationary escalator starting in 2036 and ending at \$140 per tonne in 2040. Generators in Ontario are assumed to be subject to the 310 tonnes/GWh performance standard throughout the forecast period (November 2026 through October 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 CO₂e in the process of generating 1 GWh of electricity would pay \$11,400 in excess emissions charges in 2026. The \$11,400 charge is determined based on CO₂e emissions of 120 tonnes (being the difference between the 430 tonnes emitted and the 310 tonnes/GWh EPS benchmark) x \$95/tonne, the excess emissions charge in 2026. That same plant would pay excess emission charges of \$12,000 in 2027, based on the same volume of excess emissions (120 tonnes), but with charges increasing to \$100/tonne in 2027. Less efficient gas-fired plants will pay more.

2.4.6 Effective 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\$4.12/MMBtu, and the forecast effective price, including the impact of excess emissions charges, is C\$5.09/MMBtu.⁶

⁴ <https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/index.html>

⁵ <https://www.ontario.ca/page/emissions-performance-standards-program>

⁶ 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 CO₂e 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/Union Hub		Emissions Performance Standard	Emissions Performance Standard Price	Effective Forward Price
	US\$/MMBtu	C\$/MMBtu	tonnes/GWh	C\$/tonne	C\$/MMBtu
Nov 2026	\$2.91	\$3.95	310	\$95	\$4.88
Dec 2026	\$3.39	\$4.62	310	\$95	\$5.54
Jan 2027	\$3.58	\$4.87	310	\$100	\$5.84
Feb 2027	\$3.64	\$4.95	310	\$100	\$5.92
Mar 2027	\$3.05	\$4.15	310	\$100	\$5.12
Apr 2027	\$2.76	\$3.75	310	\$100	\$4.73
May 2027	\$2.67	\$3.63	310	\$100	\$4.61
Jun 2027	\$2.69	\$3.66	310	\$100	\$4.64
Jul 2027	\$2.83	\$3.84	310	\$100	\$4.82
Aug 2027	\$2.91	\$3.96	310	\$100	\$4.94
Sep 2027	\$2.98	\$4.05	310	\$100	\$5.03
Oct 2027	\$2.98	\$4.05	310	\$100	\$5.02
Average	\$3.03	\$4.12	310	\$99.17	\$5.09

Source: S&P Global Intelligence, Power Advisory

3. REVIEW OF FORECAST RESULTS

The results of Power Advisory's 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.

As noted previously in Wholesale Market Price reports, 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 across Ontario and the eastern United States. 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 – notably in the spring of 2027 when there are significant planned outages at the Darlington Nuclear Generating Station.

The most material change in the upcoming RPP period compared to previous forecasts is the low amount of nuclear supply. Ontario's fleet of nuclear reactors has been a source of baseload supply for decades. While the baseload nature of the nuclear fleet will not change, the amount of baseload supply will be significantly reduced. The total amount of nuclear supply in the upcoming period is 59.39 TWh compared to 79.71 TWh in the forecast for the previous RPP period. The impact of the decrease in nuclear supply is material, as it will largely be replaced by higher marginal cost gas-fired generation.

And as noted previously, price formation in the renewed market is structurally different than the legacy market. At times, there can be material differences in LMPs given certain conditions. The Ottawa zone, for example, had significantly higher congestion prices than other zones across the IAM in the winter of 2025/2026. This was a result of unique market conditions – notably a very tight supply/demand balance in Quebec that drove large volumes of exports from Ontario into Quebec, as well as transmission constraints into the Ottawa zone from other parts of Ontario. Power Advisory's modelling reflects these constraints, but volatile weather or other conditions are challenging to fully reflect in a forecast given their unpredictability.

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.

Table 6: OEMP Forecast (\$/MWh)

Month	On-Peak	Off-Peak	Average
Nov 2026	\$50.42	\$44.83	\$47.47
Dec 2026	\$64.03	\$55.54	\$59.61
Jan 2027	\$123.92	\$98.81	\$110.28
Feb 2027	\$104.75	\$90.19	\$97.19
Mar 2027	\$58.69	\$49.37	\$53.84
Apr 2027	\$85.19	\$66.45	\$76.18
May 2027	\$54.89	\$48.61	\$51.48
Jun 2027	\$62.94	\$47.74	\$55.64
Jul 2027	\$100.65	\$63.49	\$81.32
Aug 2027	\$89.88	\$61.31	\$75.02
Sep 2027	\$64.06	\$59.94	\$61.89
Oct 2027	\$48.24	\$44.43	\$46.17
Nov 2026 - Oct 2027	\$75.51	\$60.72	\$67.85

Source: Power Advisory

1) 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 Saving Time (DST).