

ONTARIO ENERGY REPORT Q3 2016

JULY – SEPTEMBER 2016
ELECTRICITY

Ontario Grid-Connected Peak Demand (Q3)

23,213 MW

set September 7, 2016, 6:00 pm EDT

Source: IESO

Transmission Grid-Connected Generation Output (Q3)

Nuclear	24.02 TWh	61.9%
Hydro	8.09 TWh	20.9%
Wind	1.6 TWh	4.1%
Gas	47.9 TWh	12.3%
Biofuel	0.14 TWh	<1%
Solar	0.16 TWh	<1%

Source: IESO

Conservation Savings (Q3)

Net Peak Demand Savings	191 MW
Net Energy Savings	46 GWh

Source: IESO

Ontario Grid-Connected Peak Demand (for 2016)

23,213 MW

set in Q3 – September 7, 2016, 6:00 pm EDT

Source: IESO

Commodity Cost – Class A (¢/kWh)

	Q3	YTD
Hourly Ontario Energy Price (Unweighted average)	2.23	1.48
Global Adjustment (Average, Class A) ¹	4.61	5.30
Total	6.84	6.78

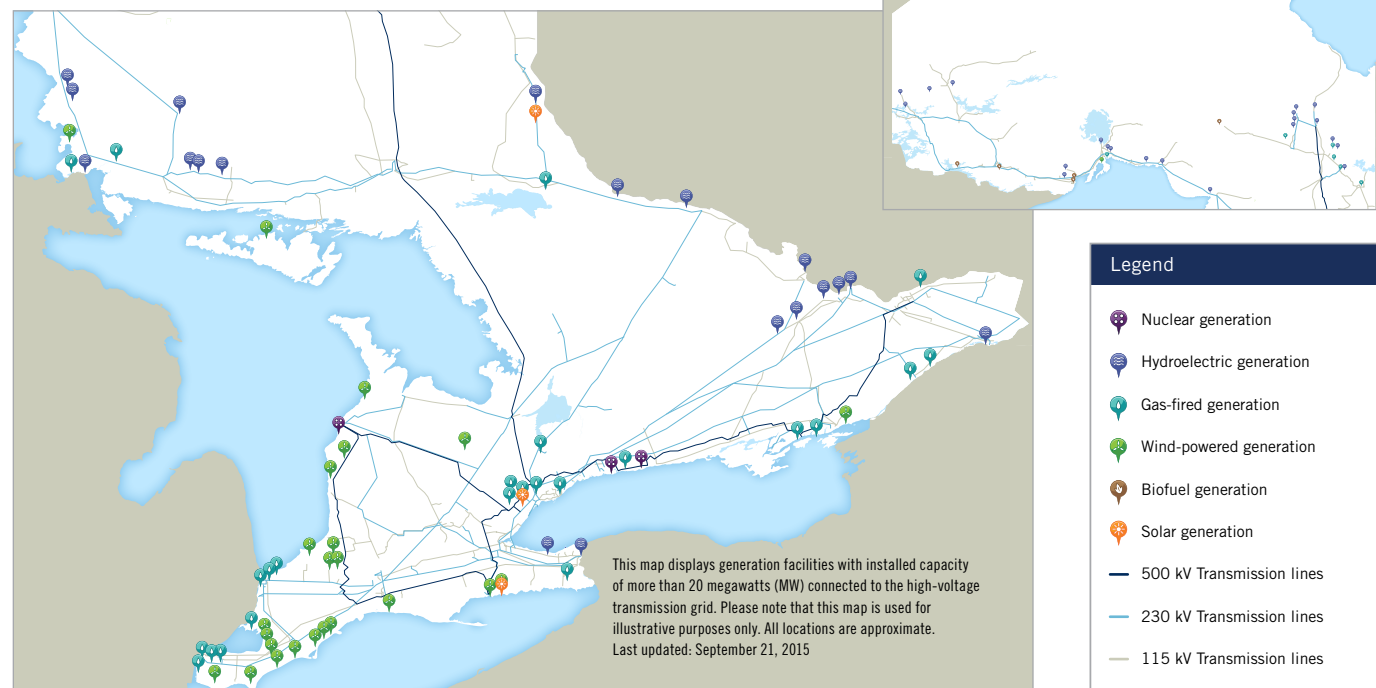
Source: IESO

Commodity Cost – Class B (¢/kWh)

	Q3	YTD
Hourly Ontario Energy Price (Weighted Average)	2.50	1.66
Global Adjustment (Average, Class B) ¹	8.24	9.47
Total	10.74	11.13

Source: IESO

Ontario's Transmission Grid

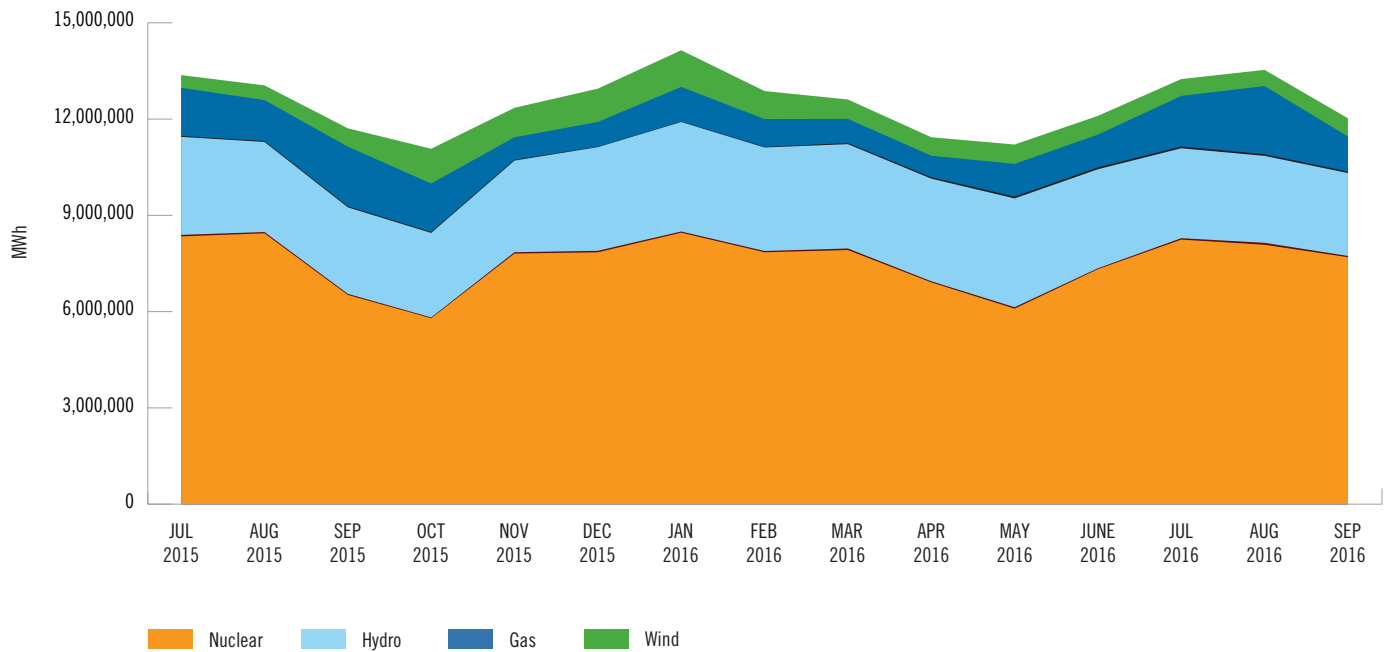


1. Class A customers are large electricity consumers that pay Global Adjustment based on their proportion of energy use during the five hours of the year with the highest demand. All other customers are Class B.

Electricity Supply

Monthly Energy Grid Output by Fuel Type (MWh)

Ontario's bulk electricity grid has a diverse supply mix, featuring baseload generators that provide energy around the clock, intermittent generators that generate when they are able (primarily wind and solar), and flexible generators that can change their output quickly (primarily natural gas).



Source: IESO

Note: Total MW value may not add up to sum of column totals due to rounding.

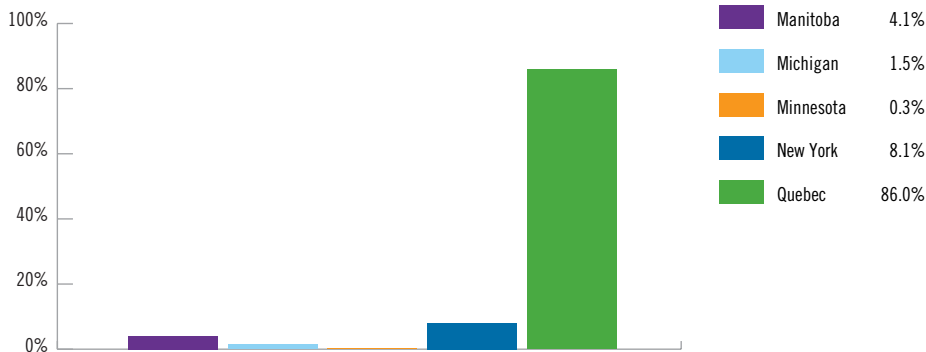
The data shown above is sourced from a report developed by the IESO, available at http://reports.ieso.ca/public/GenOutputbyFuelMonthly/PUB_GenOutputbyFuelMonthly.xml. The report uses settlement data to provide information for all self-schedulers, intermittent and dispatchable Ontario generators registered as a Market Participant. The report — which includes all grid-connected generators, plus those embedded generators that are also registered as market participants — is published monthly as per the Physical Settlement calendar.

Imports and Exports

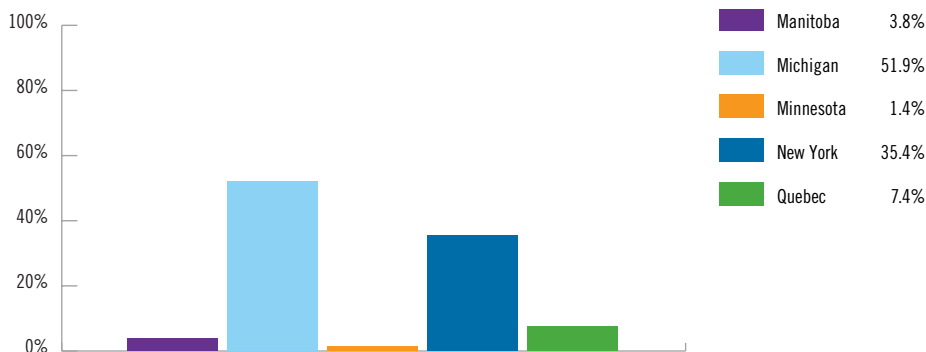
Ontario is connected to a large, stable network of transmission systems across North America, which supports system reliability and economic efficiency. Imports compete against domestic generation to provide energy at the best possible price and to support the province's needs during periods of high demand. Ontario also exports energy when prices are higher, which helps to bring in revenue that helps offset other system and infrastructure costs and can help maintain system reliability during times of surplus generation.

Ontario imports and exports power across 26 interties with two provinces and three states. While Ontario is electrically interconnected with Manitoba, Michigan, Minnesota, New York and Quebec, the interties allow for electricity trade in transactions that can reach across eastern North America, contributing to a more diversified and competitive pool of supply.

Imports



Exports



Q3 (GWh)	Manitoba	Michigan	Minnesota	New York	Quebec	Total
Imports	120	44	10	242	2,549	2,965
Exports	200	2,721	75	1,854	390	5,239

Source: IESO

Note: Numbers may not add up to totals due to rounding.

Installed Capacity Connected to Transmission Grid

Changes to installed transmission grid capacity in this quarter highlight the continuing process of renewal in Ontario's electricity sector. While nuclear, hydroelectric and natural gas production accounted for the vast majority of bulk supply, new wind, biofuel and solar generators continued to connect to the transmission grid.

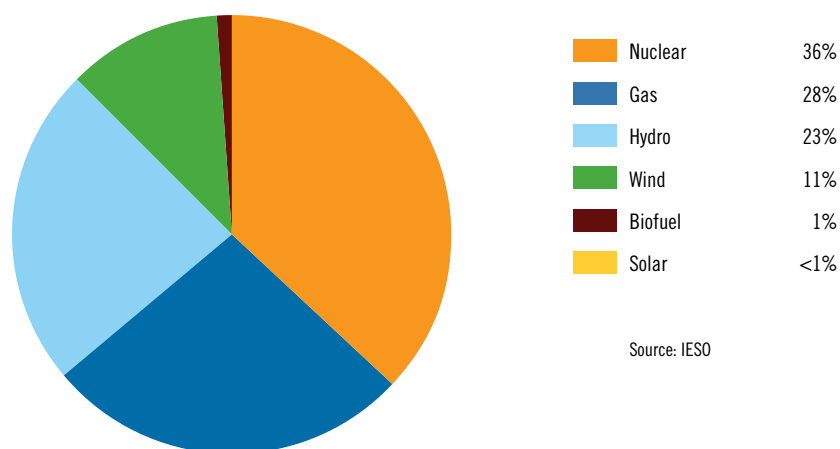
The [IESO Active Generation Contract List](#) provides the status of individual contracted electricity supply projects within different IESO procurement programs. The list is limited to generation facilities under contract to the IESO.

New Facilities Registered in Q3

The following projects have completed commissioning and the market entry process and are included as part of total installed IESO Market Participant generator capacity:

- GenSet Resource Management Inc. added a generator with 0.8 MW to their fleet

Grid-Connected Generation Capacity



Note: Data include all transmission-connected generation facilities and distribution-connected facilities that are Market Participants. Numbers may not add up to totals due to rounding.

The table below shows the increased use of renewable resources for generating electricity in the province.

Grid-Connected Generation Capacity

Year	Nuclear	Hydro	Coal	Gas*	Wind	Biofuel	Solar	Total
2016 Q3 (MW)	12,978	8,432	0	9,943	3,923	495	280	36,051
2015 (MW)	12,978	8,432	0	9,942	3,504	495	240	35,591
2014 (MW)	12,947	8,462	0	9,920	2,543	455	40	34,367
2013 (MW)	12,947	7,939	2,291	9,920	1,725	124	0	34,946
2012 (MW)	12,998	7,947	3,293	9,987	1,511	122	0	35,858
2011 (MW)	11,446	7,947	4,484	9,549	1,412	122	0	34,960

* Units that use natural gas, oil or are dual fuel, such as Lennox, NP Kirkland and NP Cochrane, are included in the Gas category.

Source: IESO

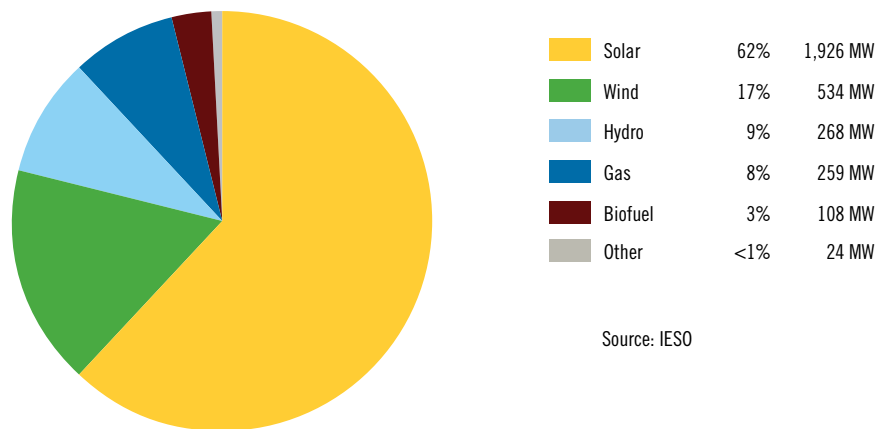
Note: Numbers may not add up to totals due to rounding.

Embedded Generation (IESO-contracted)

Embedded generators supply electricity to local distribution systems, helping to reduce demand on the transmission grid and supporting some of the needs of local communities. While wind and solar make up the majority of contracted embedded generation, the IESO has contracted for increasing amounts of hydroelectric, combined heat and power, natural gas and biofuel systems that will also connect to local distribution networks.

By the end of Q3 2016, there was more than 3,118 MW of embedded generation in commercial operation within local distribution systems.

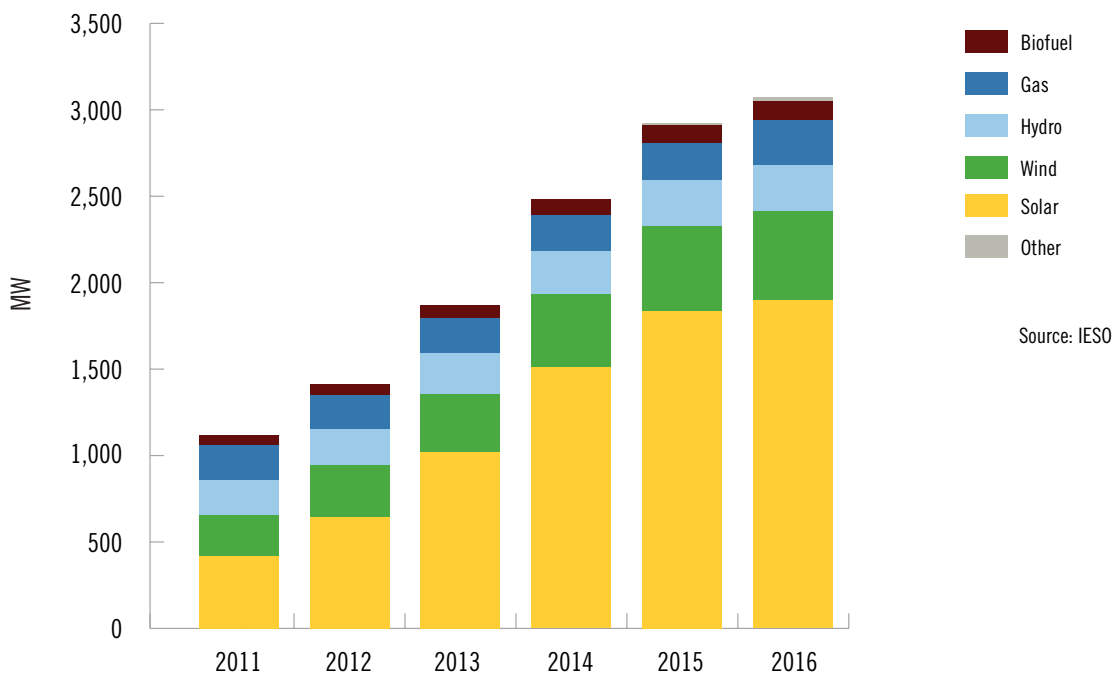
Contracted Embedded Generation Capacity in Commercial Operation (at end of Q3)



Note: Numbers may not add up to totals due to rounding.

The table below shows the increased use of embedded generation to supply electricity to local distribution systems in the province.

Contracted Embedded Generation Capacity in Commercial Operation



Note: Total IESO-contracted embedded generation in commercial operation at end of each period. Numbers may not add up to totals due to rounding.

The data shown above are sourced from the IESO Progress Report on Contracted Supply. The report provides a quarterly update on the status of supply and procurement initiatives that are under development or in commercial operation, by fuel type, and aggregates total capacities as stated in each contract, which differs from values on installed capacity used for operation purposes. The report is available at <http://www.ieso.ca/Documents/Supply/Progress-Report-Contracted-Supply-Q32016.pdf>.

Total Grid-Connected and Contracted Embedded Generation Capacity

The figures in this chart show total generation capacity at the end of the quarter: grid-connected capacity in service plus IESO-contracted embedded capacity in commercial operation.

Year	Nuclear	Hydro	Coal	Gas	Wind	Biofuel	Solar	Other	Total
2016 (MW)	12,978	8,700	0	10,202	4,457	603	2,206	24	39,169
2016 (%)	33%	22%	0%	26%	11%	2%	6%	<1%	

Source: IESO

Note: Numbers may not add up to totals due to rounding.

Available Capacity at Peak

26,420 MW (Q3)

Peak Demand	23,213 MW (Q3)	Operating Reserve Requirement	1,523 MW (Q3)
Minimum Demand	10,855 MW (Q3)		

Source: IESO

Available capacity is all installed grid-connected capacity, less allowances made for seasonal derates, planned outages and the capacity of energy-limited resources. Reserves are required to ensure that the forecast Ontario Demand can be supplied with a sufficiently high level of reliability. Operating Reserve is the amount of supply resources required to handle the loss of the largest contingency on the grid, plus the loss of half the amount of the second largest contingency. More information on the criteria, tools and methodology the IESO uses to perform resource adequacy assessments can be found at http://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2015jun.pdf.

Conservation

As part of the Conservation First Framework for 2015-2020, the province established a target of 7 terawatt-hours (TWh) in electricity savings to be achieved through conservation programs offered by local distribution companies (LDCs). The province also established a target of 1.7 TWh to be achieved through the Industrial Accelerator Program, which is delivered by the IESO to transmission-connected customers. Overall the province expects to achieve 8.7 TWh in savings by December 31, 2020.

The IESO has conditionally approved the CDM Plans of all 73 LDCs covered by the framework. Approved CDM plans are posted at: <http://www.ieso.ca/Pages/Conservation/Conservation-First-Framework/Conservation-and-Demand-Management-Plans.aspx>.

Conservation Portfolio Progress – Preliminary Unverified Incremental Results (as of Q3)

Incremental Progress		Q3 2016*
LDC Delivered Programs	Net Peak Demand Savings (MW)	9
	Net Energy Savings (GWh)	29
IESO and other Non-LDC Programs	Net Peak Demand Savings (MW)	182
	Net Energy Savings (GWh)	17
Total Net Peak Demand Savings (MW)		191
Total Net Energy Savings (GWh)		46

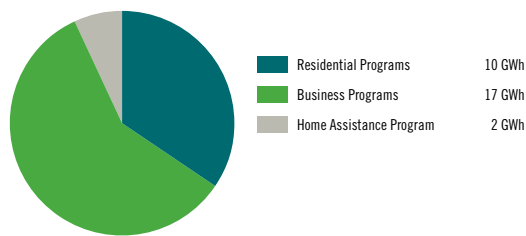
*Results are presented at the generator level; totals may not align due to rounding.

Source: IESO

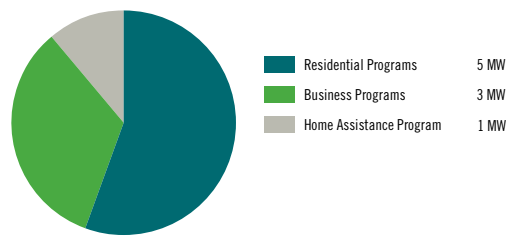
Note: All reported LDC activity and savings are based on projects reported and invoiced to the IESO only. Any projects that have an installation date in Q2 2016 are excluded.

Energy Savings through LDC-led Conservation Programs (Q3)

Net Energy Savings



Peak Demand Savings



Source: IESO

Note: Preliminary unverified results (as of Q3). Totals may not align due to rounding.

Demand Response (DR)

Demand response and peak savings programs benefit the electricity system and lower energy costs for consumers by contributing to overall peak savings for the province.

Demand response in the wholesale market is being transitioned from the contract-based Capacity-Based Demand Response (CBDR) program to an annual DR Auction. The DR Auction provides a transparent and cost-effective way to select the most competitive providers of DR, while ensuring that all providers are held to the same performance obligations. As the capacity from CBDR contracts expire, that expiring capacity will be made available for competitive selection in the DR Auction.

The first DR Auction was held in December 2015 and successfully secured 392MW and 404MW of DR capacity for the upcoming six-month Summer and Winter commitment periods respectively, which became available in May 2016.

More information on the Demand Response Auction is available at: <http://www.ieso.ca/Pages/Participate/Demand-Response-Auction>

Peak Savings

The Industrial Conservation Initiative (ICI) encourages large consumers to shift their energy use away from system-wide peaks. Customers who are able to reduce their impact on peaks benefit the system by reducing the need to build new infrastructure. Participating customers are assessed an individual Global Adjustment (GA) rate, based on the percentage that their demand contributes to the top five system coincident peaks measured during a defined base period.

The table below lists the top five daily peaks for the most recent base period, which began on May 1, 2014, and ended on April 30, 2015. Three of the top five Ontario demand peaks occurred in the first quarter of 2015.

Industrial Conservation Initiative Coincident Peak Values (for base period May 1, 2014 to April 30, 2015)

Date	Hour Ending	Net Ontario Load (MW)	Embedded Generation (MW)	Total (MW)
January 7, 2015	19	21,118.570	491.57	21,610.140
February 19, 2015	20	20,976.264	440.031	21,416.295
August 26, 2014	17	20,967.233	682.792	21,650.025
February 23, 2015	20	20,862.399	539.973	21,402.372
September 5, 2014	17	20,830.888	884.74	21,715.628

Source: IESO

Note: The value in the Total (MW) column is the number used to calculate a customer's Peak Demand Factor. The above values are used for the adjustment period July 1, 2015 to June 30, 2016.

Information on peak tracking can be found at <http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-A.aspx>

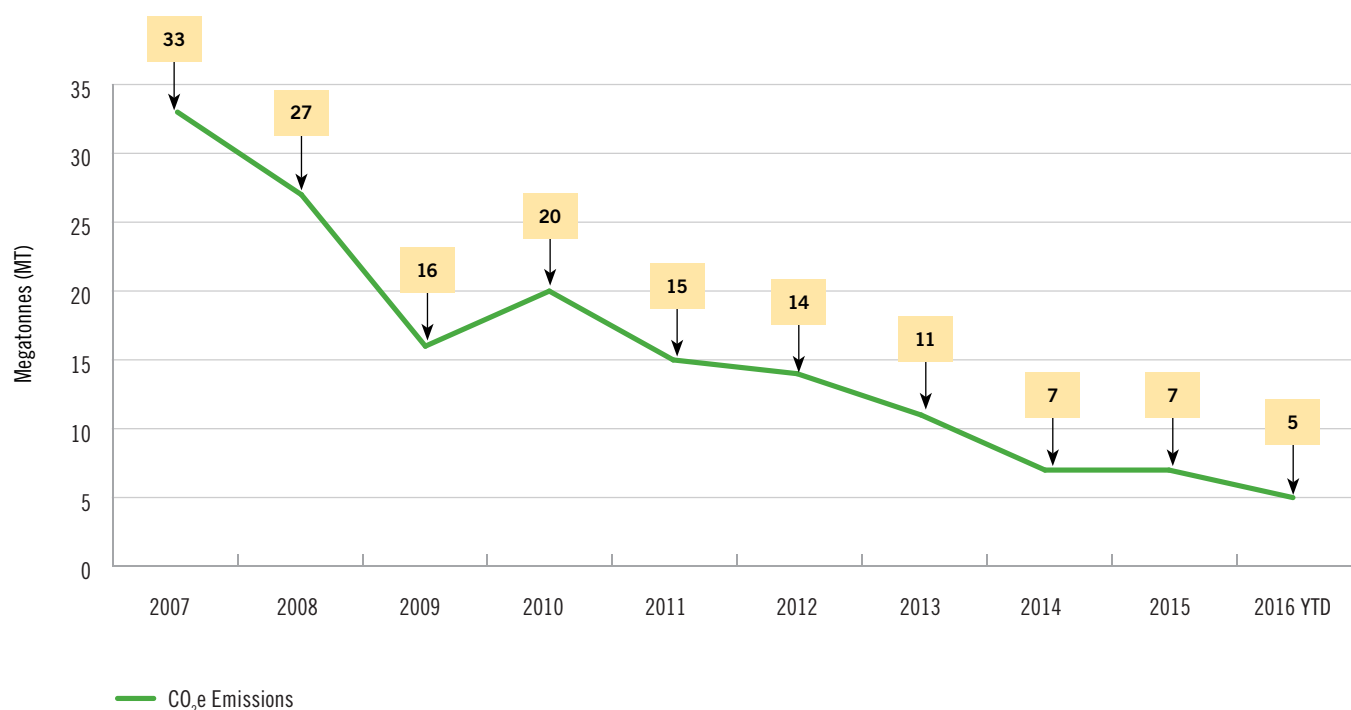
More information on the ICI is available at <http://www.ieso.ca/Documents/settlements/ICI-Backgrounder-Jan2017.pdf>

Greenhouse Gas Emissions

The marked decline in greenhouse gas emissions is a result of the phase-out of coal-fired electricity generation in the province and uptake of renewable generation and conservation measures. Emissions of oxides of sulphur (SO_x) – which are predominantly a by-product of coal combustion – have also shown a marked decrease with the phase-out of coal-fired electricity.

CO₂ Emissions for the Ontario Electricity Sector

The chart below shows annual CO₂ emissions for the years 2005-2015. Year-to-date CO₂ emissions in Q3 2016 totalled 5 Megatonnes (MT).



Source: IESO, Environment Canada

Air Contaminants

Air contaminants, including oxides of sulphur (SO_x), oxides of nitrogen (NO_x) and fine particulate matter ($\text{PM}_{2.5}$), are also released during combustion of fossil fuels.

Air Contaminants for the Ontario Electricity Sector (Tonnes)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	Q3 YTD 2016
SO _x Emissions	105,420	76,020	30,768	38,448	11,971	10,342	10,192	847	620	289
NO _x Emissions	43,846	38,314	24,389	28,130	18,988	19,077	17,183	11,520	8,877	5,273
PM _{2.5} Emissions	1,876	1,314	1,779	2,120	562	478	439	281	249	115

Source: IESO, Environment Canada

Electricity Demand

Electricity demand is generally shaped by several factors that have differing impacts – those that increase demand (population growth, economic change), those that reduce demand on the grid (conservation, embedded generation) and those that shift demand (time-of-use rates, the Industrial Conservation Initiative). The impact of each of these factors on electricity consumption varies by season and time of day.

Even as the Ontario economy has moved beyond the 2008 recession, demand has remained flat. This trend is expected to continue as capacity and energy margins remain adequate and can be attributed in part to the successful implementation of conservation initiatives.

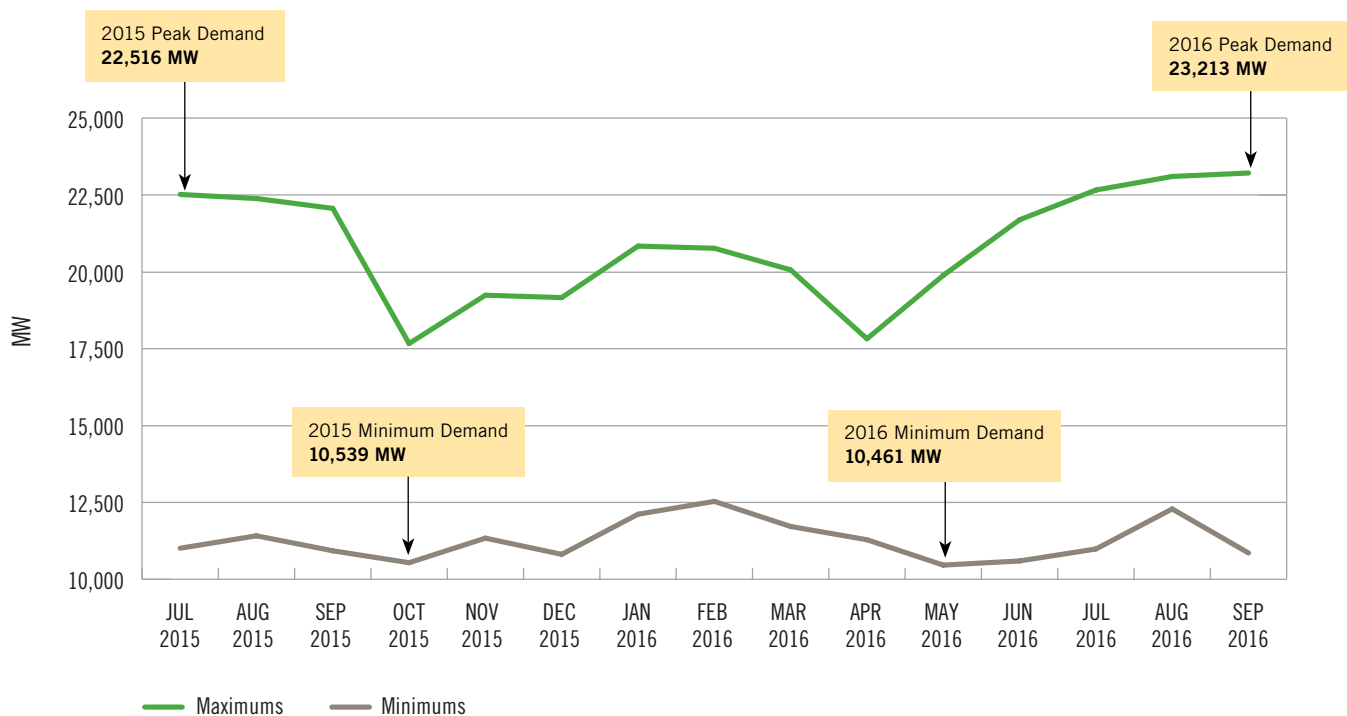
Growth in embedded solar and wind generation capacity and on-going conservation initiatives reduce the need for energy from the bulk power system, while also putting downward pressure on peak electricity demands.

Ontario Grid-Connected Peak Demand – as end of Q3

23,213 MW set in Q3 – September 7, 2016, 6:00 pm EDT

In Q3 2016 we have seen a slight increase in overall demand, up by 0.97%, when compared to Q3 in 2015, with June being warmer year on year.

Ontario Monthly Peaks and Minimums (MW)



Source: IESO

Forecast Demand Peaks

The demand for electricity on the provincial grid is forecast on a rolling 18-month basis. An assessment is done to assure the adequacy of the existing and proposed generation and transmission facilities to meet demand needs. The chart below presents normal weather forecasts, representing a typical peak for the time of year, and extreme weather forecasts that reflect severe weather conditions. The impacts of time-of-use rates and the Industrial Conservation Initiative – which incents customers to reduce demand in peak demand hours – are also factored into the demand forecast in this report.

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2016-2017	21,914	23,170
Summer 2017	22,512	24,851
Winter 2017-2018	21,811	23,017

Source: IESO 18-Month Outlook

Q3 Ontario Grid-Connected Energy Demand (TWh)

Year	Total (TWh)
2016	36.69
2015	35.26
2014	34.27
2013	35.66
2012	37.13

Source: IESO Power Data, Demand Overview

Note: Total does not include the impact of embedded generation to reduce demand.

Historical Totals – Annual Ontario Grid-Connected Energy Demand (TWh)

Year	Total (TWh)	Change Over Previous Year
2015	137.0	-2.00
2014	139.8	-0.64
2013	140.7	-0.42
2012	141.3	-0.14
2011	141.5	-0.35

Source: IESO Power Data, Demand Overview

Note: Total does not include the impact of embedded generation to reduce demand.

Electricity Prices

Commodity Cost (¢/kWh)

Commodity cost comprises two components, the wholesale price (the Hourly Ontario Energy Price) and the Global Adjustment. The commodity cost is only a portion of the total energy bill.

Class A

Month (¢/kWh)	JUL 2015	AUG 2015	SEP 2015	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	2016 YTD Avg.
HOEP*	2.03	2.19	2.99	2.41	0.93	1.00	1.28	1.15	0.52	0.57	1.2	1.87	2.10	3.05	1.53	1.48
Average Class A Global Adjustment Rate	4.76	4.56	3.77	3.83	6.01	5.44	5.62	5.82	5.85	5.75	5.6	5.27	4.90	4.22	4.73	5.30
Total Cost of Commodity	6.79	6.75	6.76	6.24	6.94	6.44	6.90	6.97	6.37	6.32	6.8	7.14	7.00	7.05	6.26	6.78

*(Unweighted) average of Hourly Ontario Energy Prices to reflect a typical (flat) industrial consumption profile.

Class B

Month (¢/kWh)	JUL 2015	AUG 2015	SEP 2015	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	2016 YTD Avg.
HOEP**	2.22	2.34	3.19	2.51	1.03	1.10	1.37	1.26	0.59	0.61	1.34	2.02	2.34	3.29	1.75	1.66
Class B Global Adjustment Rate	7.88	8.01	6.70	7.54	11.32	9.47	9.18	9.85	10.61	11.13	10.75	9.55	8.31	7.10	9.53	9.47
Total Cost of Commodity	10.1	10.35	9.89	10.05	12.35	10.57	10.55	11.11	11.20	11.74	12.09	11.57	10.65	10.39	11.28	11.13

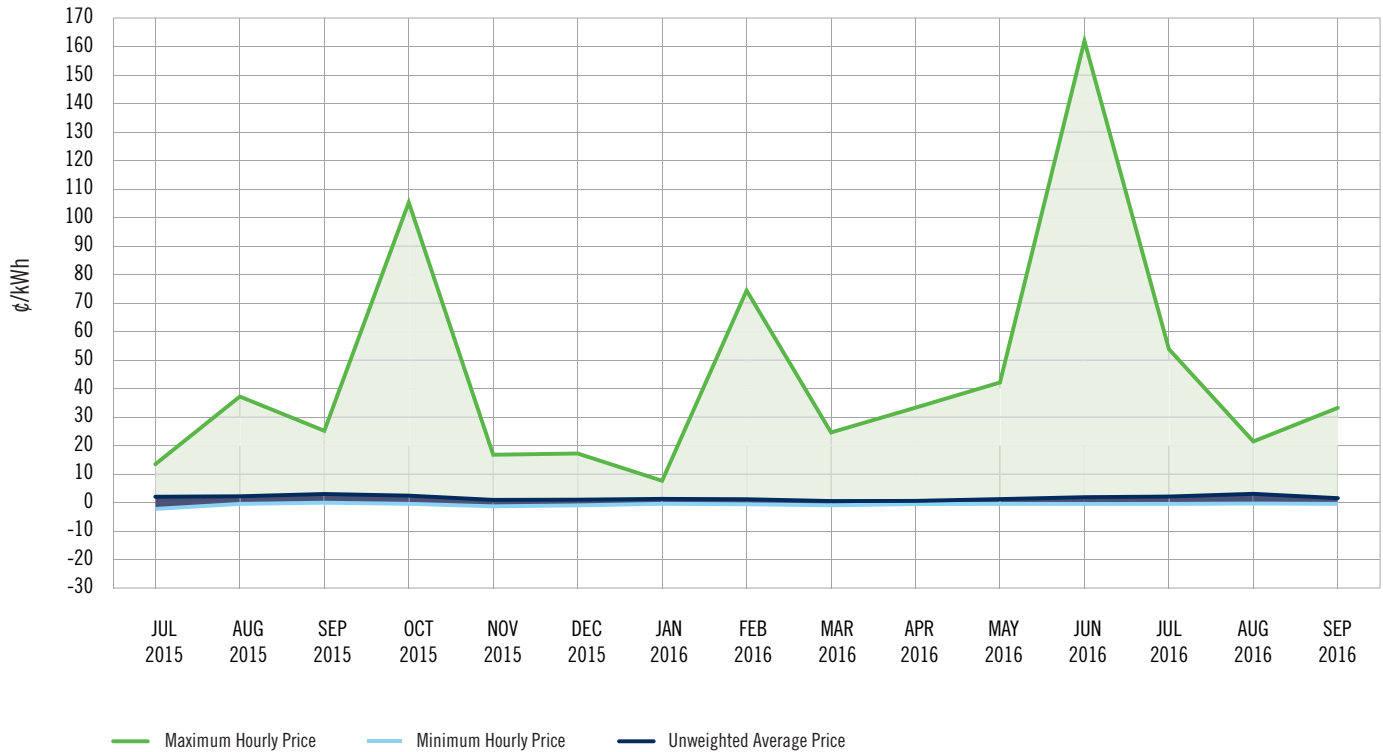
**Averages are weighted by the amount of electricity used throughout the province within each hour to broadly reflect the consumption profile of Class B (i.e., residential and commercial) consumers.

***Totals do not sum due to dollar values that are rounded down to cents.

Source: IESO

Monthly Wholesale Electricity Prices (¢/kWh)

The wholesale electricity price fluctuates by the hour. This chart shows the highest, lowest and average wholesale prices for each month. The monthly price varies depending on factors in the electricity market that shift the energy price higher or lower. A higher average monthly price exerts a downward pressure on costs that needs to be recovered through Global Adjustment, illustrated below.



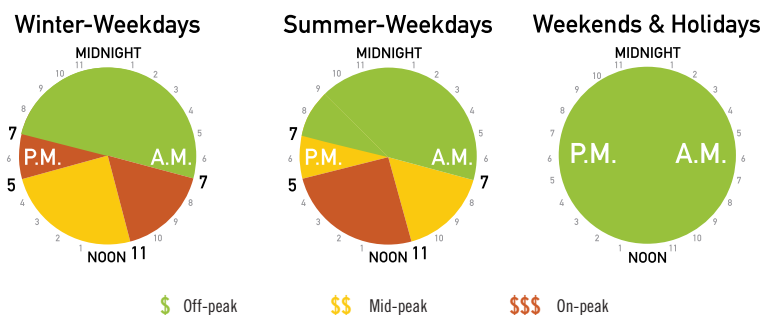
Source: IESO

Time-of-Use Pricing under the Regulated Price Plan (RPP)

In accordance with the mandate provided under the Ontario Energy Board Act, the OEB has developed the regulated price plan (RPP), which provides eligible residential and small business consumers with stable and predictable electricity pricing, encourages conservation and ensures the price consumers pay for electricity better reflects the price paid to generators. The plan has been in place since 2005.

The RPP is established by forecasting the cost of supply for RPP customers for an upcoming year and determining the prices that will recover those forecast costs from eligible customers. Consumers with eligible time-of-use (or “smart”) meters that can determine when electricity is consumed during the day will pay the RPP under a time-of-use price structure. The prices for this plan are based on three time-of-use periods per weekday. These periods are referred to as off-peak, mid-peak and on-peak and are shown in the figure below. The hours for mid-peak and on-peak periods are different in the summer and winter months to match energy consumption patterns in those seasons.

Summer and Winter Time-of-Use Hours



Source: OEB

RPP prices reflect a forecast of prices on the Ontario wholesale electricity market, as well as other components of supply costs, such as those resulting from contracts. These costs are allocated to TOU consumption periods based on the type of supply that provides value at those times. For example, costs for always-on baseload sources of generation (such as nuclear) are allocated across all periods whereas costs for demand response conservation programs are only allocated to on-peak periods. The lowest (off-peak) price is below the average RPP supply cost, while the other two price periods are above it. The time-of-use (TOU) prices applicable in Q3 2016 for consumers with eligible time-of-use meters are shown in the table below.

RPP Time-of-use prices effective May 1, 2016

Time-of-use RPP Prices – ¢/kWh	Off-Peak	Mid-Peak	On-Peak	Average Price
Price (¢)	8.7	13.2	18.0	11.1
% of TOU Consumption	65%	17%	18%	

Sample Residential Monthly Bill

	Electricity	Delivery	Regulatory	DRC*	HST	OCEB	Total Bill
Monthly Cost (\$)	83.54	53.94	4.92	0.00	18.51	0.00	160.91

*The Debt Retirement Charge (DRC) ceased being effective as of December 31, 2015.

Source: OEB

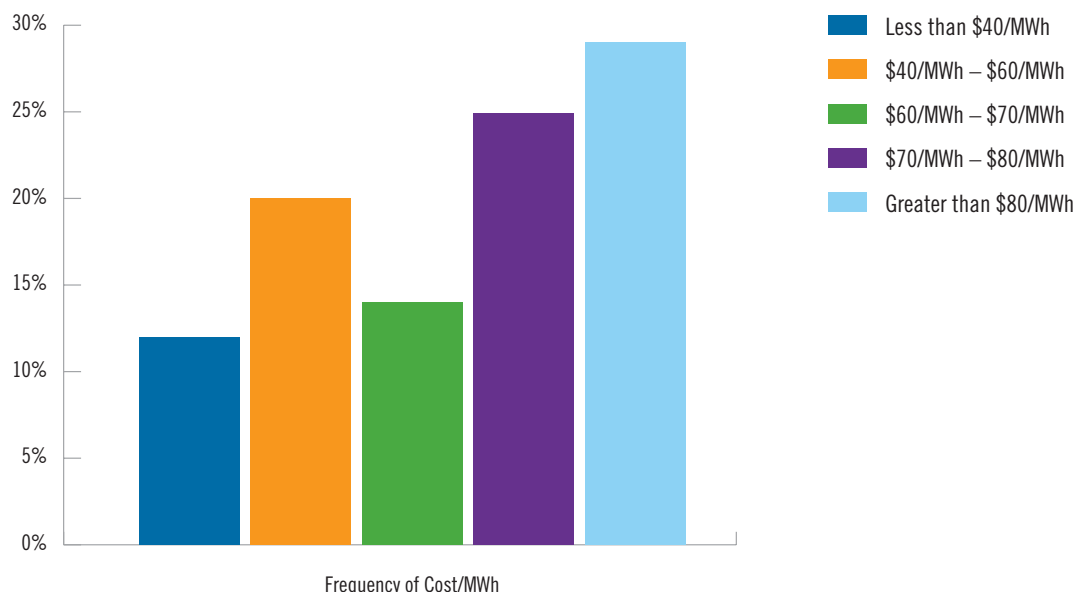
This table shows a residential monthly bill for a Toronto Hydro residential RPP TOU customer with monthly usage of 750 kWh² as of May 1, 2016, with 65% of consumption occurring off-peak, 17% occurring mid-peak and 18% occurring on-peak. For consumers in other service territories, delivery cost will vary and is determined according to their local distributor's distribution rates (as approved by the OEB). For additional information please see the OEB's bill calculator <http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility>.

2. On April 14, 2016, the *Report of the Ontario Energy Board: Defining Ontario's Typical Electricity Customer* was released in which the OEB determined that 750 kWh per month would be the standard used for illustrative purposes.

Ontario Industrial Electricity Rates

Industrial electricity consumers can either be directly connected to the high-voltage transmission grid or receive electricity from their local distributor (e.g., Toronto Hydro). Directly-connected consumers do not pay distribution charges, thus lowering their electricity cost. The table below shows the distribution of average all-in prices for all directly-connected consumers in Ontario for 2015. In Ontario, electricity rates for large industrial consumers in Ontario vary by customer as they are determined by individual consumption patterns. Generally speaking, the less energy a large industrial uses during peak hours, the more these consumers reduce their impact on the provincial power system as well as their electricity costs. For most, the commodity cost incorporates both the fluctuating market price and the allocation of the Global Adjustment based on their energy use during peaks.

Transmission-Connected Industrial Rates³ (2015)



The table below shows average all-in electricity prices for a distribution-connected industrial consumer in several service territories.⁴

Distribution-Connected Industrial Rates (2015)

\$/MWh	Windsor (EnWin)	Hamilton (Horizon)	Ottawa	Sudbury	Toronto*
HOEP**	\$21.76	\$21.79	\$21.81	\$22.60	\$21.84
Class A Global Adjustment	\$46.26	\$46.33	\$46.37	\$48.05	\$46.44
Delivery	\$14.55	\$19.12	\$19.10	\$17.08	\$17.43
Regulatory	\$5.73	\$5.73	\$5.74	\$5.95	\$5.75
DRC	\$7.00	\$7.00	\$6.90	\$7.00	\$7.00
All-In Price	\$95.29	\$99.97	\$99.91	\$100.68	98.46

*The distribution cost estimate for an industrial customer in Toronto reflects the assumption that 1 kVA is 1 kW for billing purposes.

**HOEP is the arithmetic average for all hours in 2015. The Global Adjustment shown in the table is an average of all distribution-connected Class A consumers for 2015. Both quantities have been adjusted for losses using the applicable primary metered loss factor for each distributor.

Source: IESO and OEB

3. Does not include Northern Industrial Electricity Rate Program.

4. Data in the table is for a hypothetical consumer with a monthly peak demand of 5 megawatts and an 85% load factor, reflecting delivery and regulatory charges in effect in Q4 2015.

Load factor is an expression of how much energy was used in a time period, expressed as a percentage of what would have been used if consuming at full potential for the entire period.

A 30 day month is assumed.

2015 Indicative Industrial Electricity Prices (Canadian ¢/kWh)

The table below compares indicative retail industrial electricity prices across North American jurisdictions. For reference, Ontario – South reflects the average price for year-to-date May 2015. Ontario – North is based on the same figure, along with the 2 cent per kilowatt hour Northern Industrial Electricity Rate Program rebate. See footnote for more details.

Jurisdiction	Cost	Jurisdiction	Cost	Jurisdiction	Cost
1. Manitoba	4.67	22. Oregon	7.72	43. Virginia	9.23
2. Quebec	5.17	23. West Virginia	7.80	44. South Dakota	9.31
3. Washington	5.64	24. Saskatchewan	7.81	45. Kansas	9.54
4. Alberta	5.87	25. Nevada	7.83	46. Nebraska	9.56
5. Ontario – North	6.35	26. Arizona	8.00	47. Pennsylvania	9.59
6. Oklahoma	6.64	27. Idaho	8.05	48. Wisconsin	9.87
7. Montana	6.68	28. North Carolina	8.09	49. Nova Scotia	10.02
8. Kentucky	6.80	29. New Mexico	8.09	50. North Dakota	10.75
9. British Columbia	7.04	30. Illinois	8.24	51. Florida	10.79
10. Iowa	7.06	31. Ontario – South	8.35	52. Delaware	10.96
11. Louisiana	7.06	32. Mississippi	8.41	53. Maryland	11.86
12. Canadian Average	7.31	33. Newfoundland	8.65	54. Maine	12.64
13. Missouri	7.32	34. U.S. Average	8.71	55. Vermont	13.14
14. Georgia	7.35	35. New York	8.72	56. California	13.85
15. Texas	7.37	36. Indiana	8.74	57. New Jersey	14.44
16. New Brunswick	7.48	37. Ohio	8.75	58. New Hampshire	17.17
17. Arkansas	7.49	38. Wyoming	8.87	59. Massachusetts	17.56
18. Tennessee	7.53	39. Minnesota	8.89	60. Connecticut	17.58
19. Alabama	7.58	40. Prince Edward Island	8.90	61. Alaska	18.85
20. South Carolina	7.68	41. Colorado	9.05	62. Rhode Island	19.97
21. Utah	7.70	42. Michigan	9.13	63. Hawaii	31.10

Note: Estimates may differ from actual costs to a consumer based on location, connection, and operational characteristics. Prices exclude taxes and, in other jurisdictions, participation in any applicable jurisdictional benefit programs.

The Ontario industrial price is based on the average all-in price for year-to-date May 2015, and includes the Hourly Ontario Energy Price (arithmetic average), Class A Global Adjustment, delivery, wholesale market service charges and the Debt Retirement Charge. The 2 cent per kilowatt hour difference between northern Ontario and southern Ontario reflects the Northern Industrial Electricity Rate Program rebate.

All other Canadian prices (except Ontario) are from the Hydro Quebec Rate Comparison for rates effective April 1, 2015 for select local distribution companies servicing specific cities. Where Hydro Quebec reports prices for two cities in a province (e.g., Calgary and Edmonton), an average of the two is used; in provinces where only one city is reported (e.g., Vancouver in BC, Montreal in QC), that one price is used to represent the province for indicative comparison purposes. In the Hydro Quebec Rate Comparison, a large consumer reflects 5 MW with monthly consumption of 3,060 MWh.

American jurisdictions reflect year-to-date May 2015 data from the US Energy Information Administration's survey of approximately 500 of the largest electric utilities. The price reflects the average revenue reported by the electric utility from electricity sold to the industrial sector. The value represents an estimated average retail price, but does not necessarily reflect the price charged to an individual consumer. Prices are converted at an exchange rate of 1 USD = 1.30 CAD, an approximation of the average for 2015 (1 USD = 1.2787 CAD).

Electricity – What's New

A collection of electricity reports and publications.

Information	Published By	Date
 18 Month Outlook	IESO	December 15, 2016
 Quarterly Conservation Report	IESO	December 15, 2016
 Progress Report on Contracted Electricity Supply	IESO	December 15, 2016
 Ontario Planning Outlook	IESO	September 1, 2016
 Environmental Emissions Data Reports (Pickering, Darlington, Western Waste Management)	OPG	December 12, 2016
 PowerNews	OPG	December 12, 2016
 OPG Quarterly Financial Results	OPG	November 10, 2016
 Performance Reports (Pickering, Darlington)	OPG	December 12, 2016
 Darlington Refurbishment – Semi-Annual Performance Report	OPG	September 1, 2016
 Hydro One Quarterly Report	Hydro One	November 11, 2016
 QRAM Regulated Natural Gas Rates	OEB	September 22, 2016
 Regulated Price Plan: Price Report, November 1, 2016 to October 31, 2017	OEB	October 19, 2016