ONTARIO ENERGY QUARTERLY Q1 2020

JANUARY – MARCH 2020
ELECTRICITY

Ontario Grid-Connected Peak Demand (Q1)

19,928 MW

Set on January 17, 2020, 6:00 pm EST

Source: IESO

Ontario Grid-Connected Peak Demand (YTD)

19,928 MW

Set in Q1 – January 17, 2020, 6:00 pm EST

Source: IESO

Transmission Grid-Connected Generation Output (Q1)

Nuclear	22.8 TWh	58.9%
Hydro	9.6 TWh	24.9%
Wind	3.8 TWh	9.8%
Gas	2.3 TWh	6.0%
Biofuel	< 1 TWh	0.3%
Solar	< 1 TWh	0.3%

Source: IESO

Commodity Cost – Class A (¢/kWh)

	Q1	YTD
Hourly Ontario Energy Price (Arithmetic average)	1.38	1.38
Global Adjustment (Average, Class A)[1]	5.97	5.97
Total	**7.35**	**7.35**

Source: IESO

Commodity Cost – Class B (¢/kWh)

	Q1	YTD
Hourly Ontario Energy Price (Weighted Average)	1.44	1.44
Global Adjustment (Average, Class B)[1]	11.14	11.14
Total	**12.58**	**12.58**

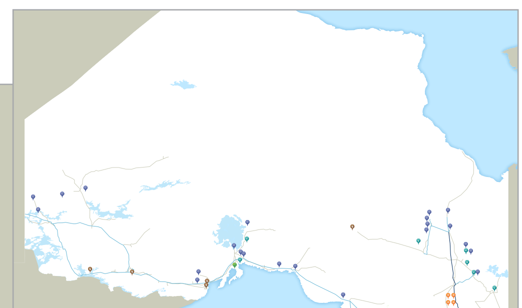
Source: IESO

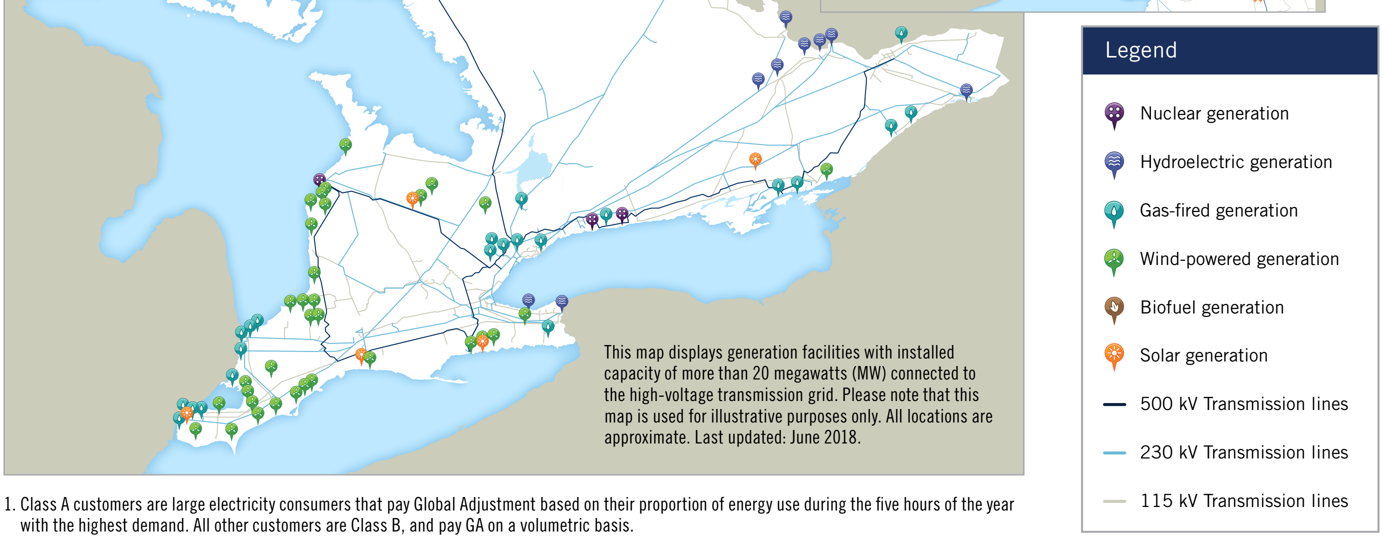
Conservation Savings (Q1)

Net Peak Demand Savings	28 MW
Net Energy Savings	176 GWh

Source: IESO

Ontario's Transmission Grid





This map displays generation facilities with installed capacity of more than 20 megawatts (MW) connected to the high-voltage transmission grid. Please note that this map is used for illustrative purposes only. All locations are approximate. Last updated: June 2018.

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, and pay GA on a volumetric basis.

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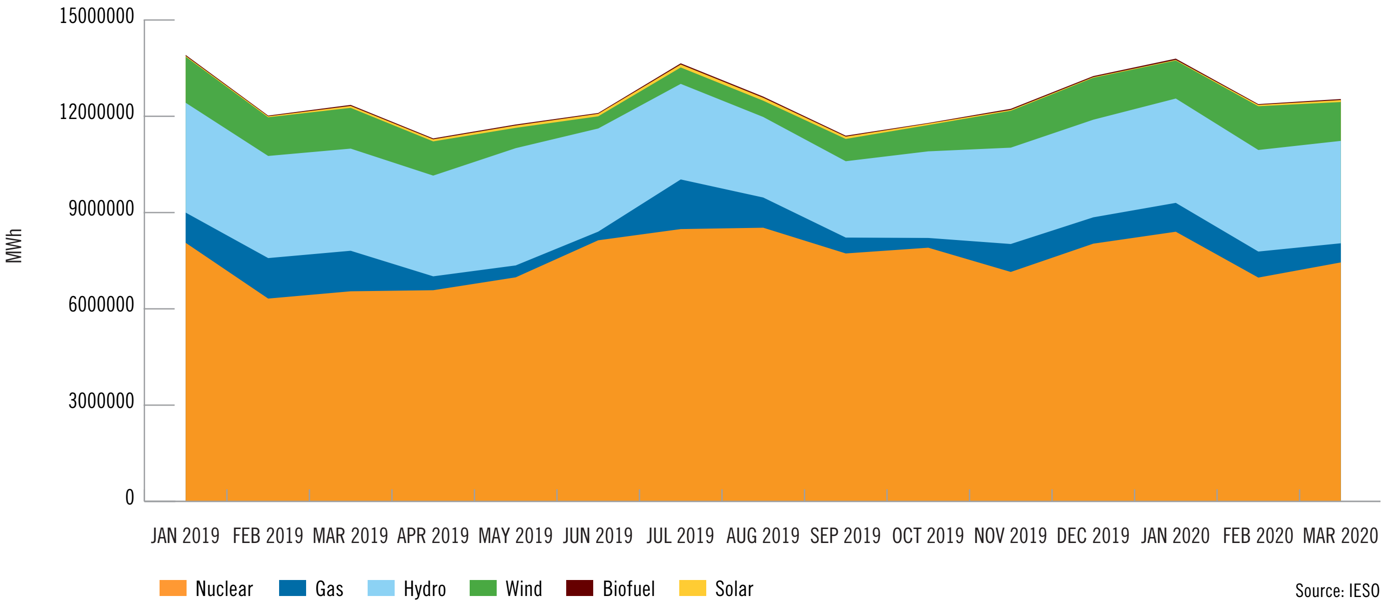
Electricity Supply

Monthly Energy Grid Output by Fuel Type

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).



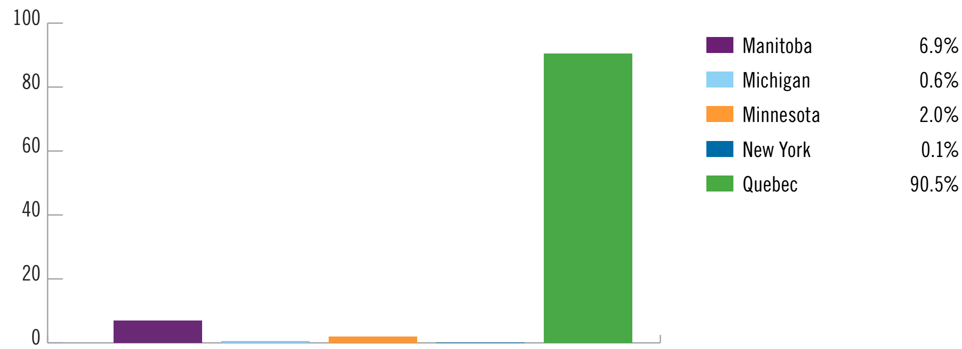
The data shown above is sourced from a report developed by the IESO, available at reports.ieso.ca/public/GenOutputbyFuelMonthly/PUB_GenOutputbyFuelMonthly.xml. The report uses settlement data to provide information for all self-schedulers, intermittent and dispatchable Ontario generators registered as 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

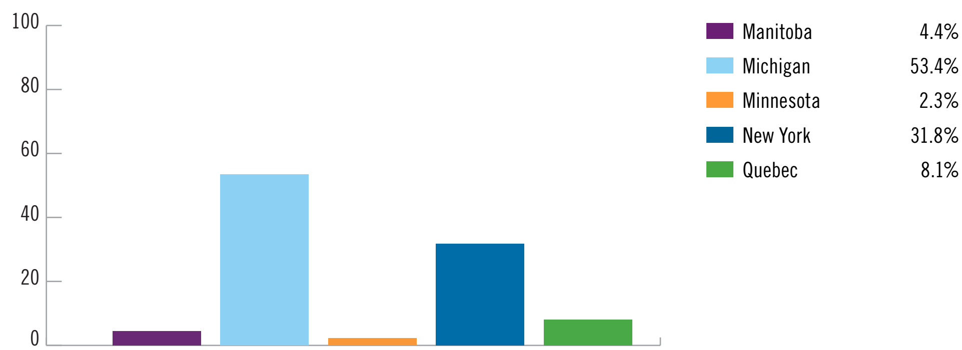
Ontario is connected to a large, stable network of transmission systems across North America, which supports system reliability and economic efficiency. Imports compete against domestic generation to provide energy at the best possible price and to support the province's needs during periods of high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

Q1 Imports



Q1 Exports



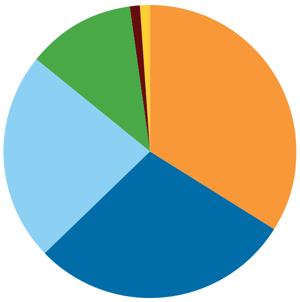
Q1 (GWh)	Manitoba	Michigan	Minnesota	New York	Quebec	Total
Imports	83.95	7.23	24.01	0.89	1,105.17	**1,221.25**
Exports	244.41	2,933.30	126.11	1,746.61	447.54	**5,497.97**

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

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 resources accounted for the vast majority of system capacity, 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.

Grid-Connected Generation Capacity (Q1)



Note: Data includes 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 (MW)	Nuclear	Hydro	Coal	Gas*	Wind	Biofuel	Solar	Total
2020 - YTD	13,009	9,065	0	11,270	4,486	295	478	**38,603**
2019	13,009	9,065	0	10,277	4,486	295	424	**37,555**
2018	13,009	8,482	0	10,277	4,486	295	380	**36,929**
2017	13,009	8,490	0	10,277	4,213	495	380	**36,863**
2016	12,978	8,451	0	9,943	3,923	495	280	**36,070**
2015	12,978	8,432	0	9,942	3,504	495	240	**35,591**
2014	12,947	8,462	0	9,920	2,543	455	40	**34,367**

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

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

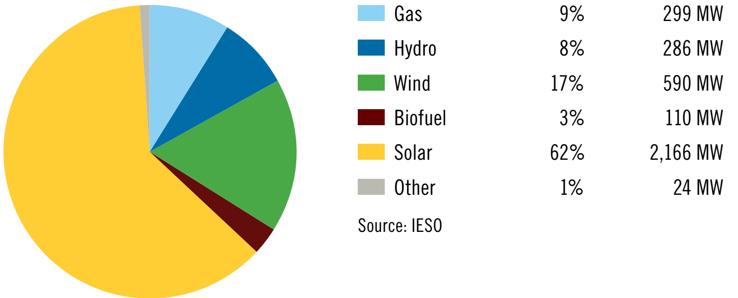
[1] A small amount (estimated 180 MW) of contracted embedded capacity is IESO-administered (market participant) generation and therefore reported in both grid-connected and contracted embedded generation totals. Totals do not include non-contracted embedded generation capacity, whose total annual output is approximately 1 TWh.

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 Q1 2020, there was 3,476 MW of contracted generation in commercial operation within local distribution systems.

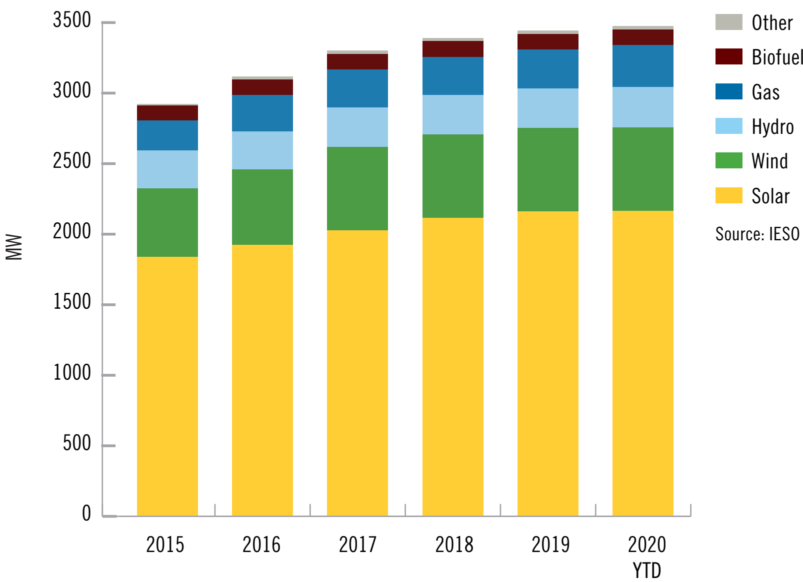
Contracted Embedded Generation Capacity in Commercial Operation (Q1)



Note: Each of the above numbers appear in the IESO Q1 Progress Report on Contracted Supply.

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 ieso.ca/power-data/supply-overview/transmission-connected-generation.

Total Grid-Connected and Contracted Embedded Generation Capacity

This table shows all grid-connected capacity and IESO-contracted embedded capacity in the province.

Year	Nuclear	Hydro	Coal	Gas	Wind	Biofuel	Solar	Other	Total
2020 Q1 (MW)	13,009	9,351	0	11,569	5,076	405	2,644	24	**42,078**
2020 Q1 (%)	31%	22%	0%	27%	12%	1%	6%	<1%	

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

Available Capacity at Peak		25,369 MW (Q1)
Peak Demand	19,928 MW (Q1)	Operating Reserve Requirement 1,985 MW (Q1)
Minimum Demand	11,120 MW (Q1)	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 ieso.ca/power-data/market-summaries-archive.

Conservation

Together the Conservation First Framework (CFF), Industrial Accelerator Program (IAP) and the Interim Framework (IF) are expected to achieve 8.7 TWh in savings. As of Q1 2020, Conservation and Demand Management (CDM) Programs have achieved 7,656 gigawatt-hours (GWh) in electricity savings. For more details on quarterly results, please see the quarterly IESO Conservation Progress Report via the IESO Conservation Reports website: ieso.ca/power-data/conservation-overview/conservation-reports.

As is common at the start of all conservation frameworks, participation levels in the Interim Framework took time to increase as new programs were implemented, program-delivery vendors were on-boarded, and customers became more familiar with new program offerings. Energy and demand savings from programs under the Interim Framework are forecasted to increase over time as more projects are completed and participation levels continue to increase. Actual savings are expected to continue to accrue through 2021-2022 as committed projects enter into service.

Prior to the COVID-19 health emergency, the IESO was forecasting to cost effectively achieve 100% of the energy savings and demand targets. The IESO is updating its 2020 forecast to account for the COVID-19 health emergency and its impact to overall energy savings and demand targets.

Conservation Portfolio Progress – Results (as of 2020 Q1)[1]

Incremental Progress		2020 Q1 Incremental*	2015-2020 Q1 Incremental	2020 Target Progress (%)
LDC & IESO Delivered CFF	Peak Demand Savings (MW)	17	888	-
	Energy Savings (GWh)	136	7,124	119
IESO Delivered IAP	Peak Demand Savings (MW)	5	128	-
	Energy Savings (GWh)	2	454	35
IESO Delivered IF	Peak Demand Savings (MW)	6.6	13.2	7.0
	Energy Savings (GWh)	38.4	78.3	5.5
Total Portfolio	**Total Peak Demand Savings (MW)**	**28**	**1,029**	**-**
	Total Energy Savings (GWh)	**176**	**7,656**	**-**

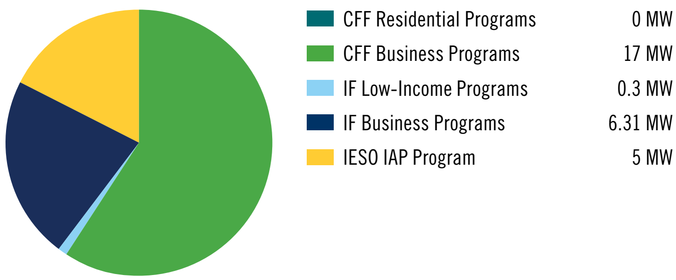
*Represents savings with an in-service date within the quarter and not savings received by the IESO since the last report

Source: IESO

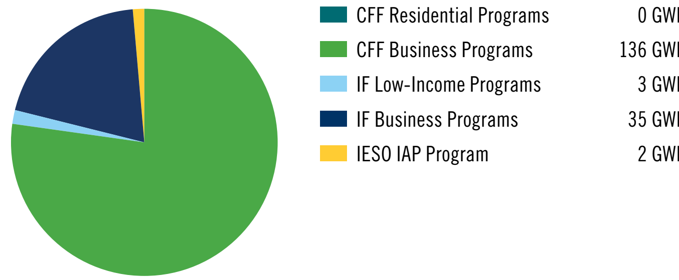
Note: Totals may not align due to rounding.

Incremental Savings (2020 Q1)

2020 Annual Peak Demand Savings



2020 Annual Energy Savings



Note: Totals may not align due to rounding

Source: IESO

[1] All conservation metrics above are presented as 'net' savings which take into consideration the actual influence of the program on participants (e.g., estimating free-ridership and spill over savings). Furthermore, all savings presented above persist until the year 2020 at the end-user level (e.g., accounting for transmission and distribution system line losses). To align savings with generation level metrics, values should be increased by factor of 6.7% for distribution system level savings or a factor of 2.5% for transmission system level savings.

Results presented are 'reported' (i.e. 'unverified') based on project installation dates corresponding to the indicated period and are based on projects reported and invoiced to the IESO as of 2020 quarter 1.

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.

Beginning in December 2015, DR capacity has been procured through a competitive DR Auction process. 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.

The December 2018 DR auction procured 818.4 MW for the summer six-month commitment period beginning on May 1, 2019, and 854.2 MW for the winter six-month commitment period beginning on November 1, 2019.

More information on the Demand Response Auction is available at: ieso.ca/en/sector-participants/market-operations/markets-and-related-programs/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. In 2017, ICI is estimated to have reduced peak demand by 1,400 MW. 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 base period that began on May 1, 2018 and ended on April 30, 2019.

Top 5 Peaks: Hours & System-Wide Consumption (Base Period: May 1, 2018 to April 30, 2019)

Date	Hour Ending	Allocated Quantity of Energy Withdrawn (MW)	Embedded Generation (MW)	Energy Storage Injections (MWh)	Total (MW)
September 5, 2018	17	22,551.315	1,076.151	0.446	**23,627.020**
July 5, 2018	15	22,415.022	1,418.704	0.008	**23,833.718**
July 4, 2018	18	22,122.730	734.709	0.393	**22,857.046**
August 28, 2018	17	21,643.799	1,069.941	0.581	**22,713.159**
September 4, 2018	17	21,379.327	803.919	0.759	**22,182.487**

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 July 1, 2019 to June 30, 2020 adjustment period.

Source: IESO

Information on peak tracking can be found at

ieso.ca/sector-participants/settlements/global-adjustment-for-class-a

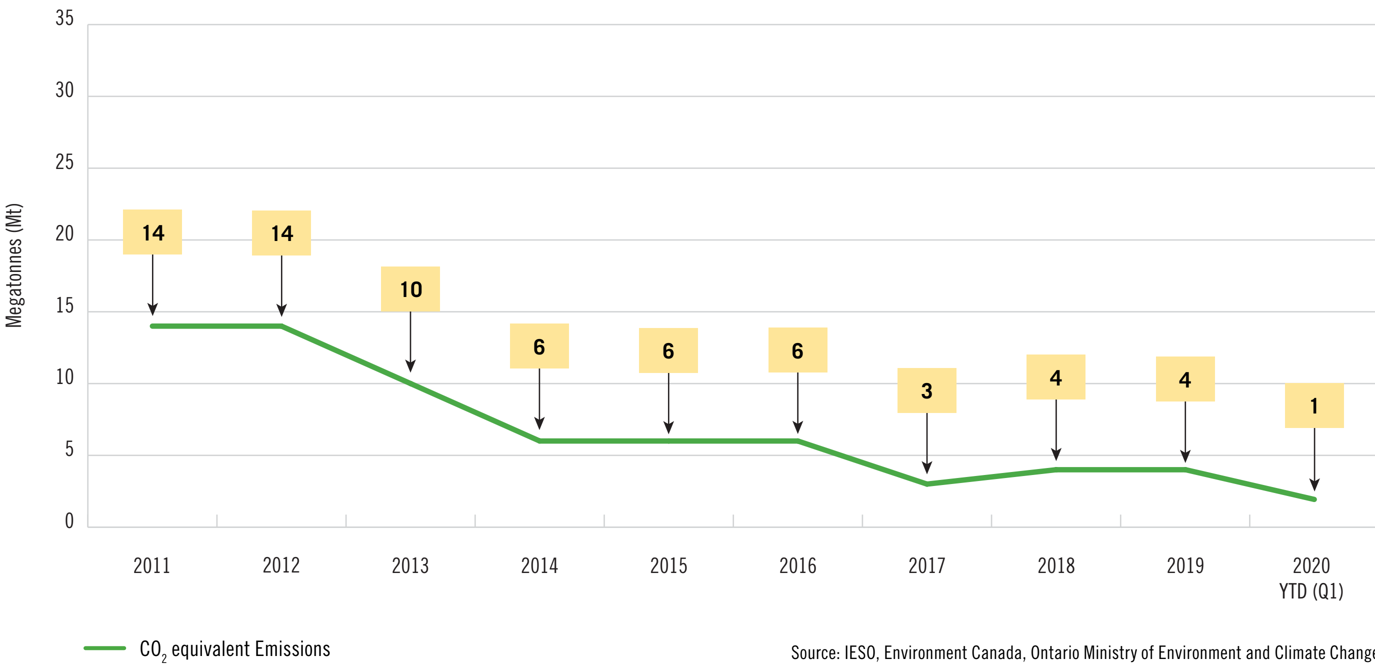
More information on the ICI is available at
ieso.ca/-/media/files/ieso/document-library/global-adjustment/ici-backgrounder.pdf?la=en.

Greenhouse Gas Emissions

The marked decline in greenhouse gas emissions (measured in tonnes of CO_2 equivalent) is a result of the phase-out of coal-fired electricity generation in the province, uptake of emissions-free 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.

Greenhouse Gas Emissions for the Ontario Electricity Sector

The chart below shows annual greenhouse gas emissions (measured in tonnes of CO_2 equivalent) for the years 2010-2020. Year-to-date greenhouse gas emissions in Q1 2020 totalled approximately 1 megatonne (Mt).



Source: IESO, Environment Canada, Ontario Ministry of Environment and Climate Change

Air Contaminants

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

Air Contaminants for the Ontario Electricity Sector (Tonnes)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SO_x Emissions	11,966	10,342	10,192	846	424	579	644	504	464	**75**
NO_x Emissions	18,198	19,867	17,973	11,448	10,355	9,323	5,695	5,924	6,010	**1,445**
$PM_{2.5}$ Emissions	518	468	445	309	262	239	195	210	212	**53**

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. As capacity and energy margins remain adequate, this trend is expected to continue, partly because of the successful implementation of conservation initiatives.

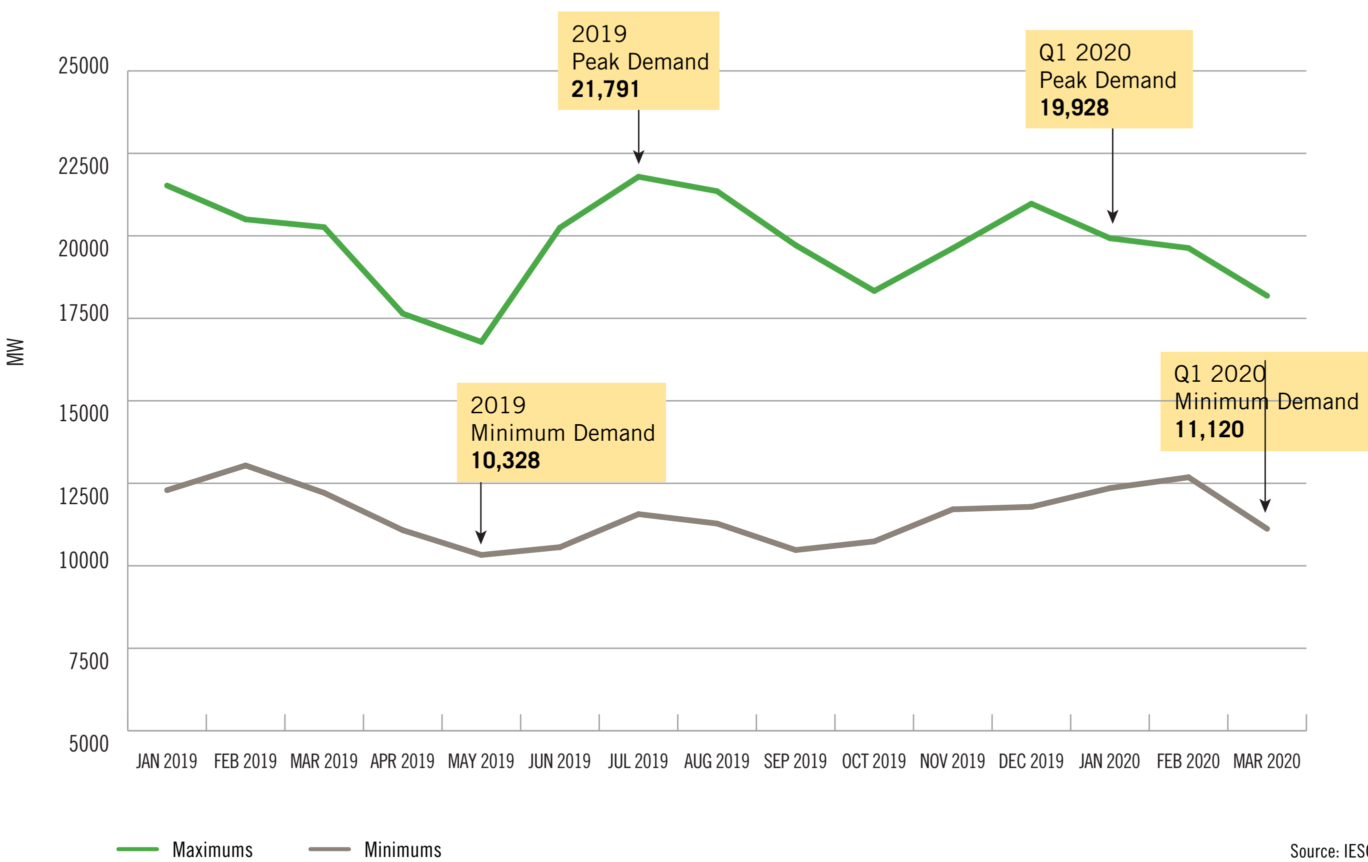
Growth in embedded solar and wind generation capacity and on-going conservation initiatives reduce the need for energy from the bulk power system, while also putting downward pressure on peak electricity demands.

Ontario Grid-Connected Peak Demand in Q1

19,928 MW

Set on January 17, 2020, 6:00 pm EST

Ontario Monthly Peaks and Minimums



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 incent 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 2019-20	21,115	22,288
Summer 2020	22,138	24,500
Winter 2020-21	21,160	22,456

Source: IESO Reliability Outlook

Ontario Grid-Connected Energy Demand

Year	Q1 Total (TWh)
2020	34.41
2019	35.73
2018	35.02
2017	34.31
2016	35.16
2015	37.47
2014	38.35
2013	36.59

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

Source: IESO Power Data, Demand Overview

Historical Totals – Annual Ontario Grid-Connected Energy Demand

Year	Total (TWh)	Change Over Previous Year
2020	34.4	n/a
2019	135.1	-2.3
2018	137.4	5.3
2017	132.1	-4.9
2016	137.0	0.0
2015	137.0	-2.8
2014	139.8	-0.9

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

Source: IESO Power Data, Demand Overview

Electricity Prices

Commodity Cost

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)	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JULY 2019	AUG 2019	SEP 2019	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	2020 YTD.
HOEP*	2.64	2.71	2.67	1.48	0.70	0.37	2.05	1.48	1.34	0.65	1.96	2.06	1.39	1.40	1.34	1.38
Average Class A Global Adjustment Rate	5.32	5.43	4.81	6.37	6.42	7.18	5.94	6.72	5.75	6.28	5.13	5.30	5.66	6.06	6.18	5.97
Total Cost of Commodity	**7.96**	**8.14**	**7.48**	**7.85**	**7.12**	**7.55**	**7.99**	**8.20**	**7.08**	**6.93**	**7.09**	**7.36**	**6.93**	**7.09**	**7.36**	**7.35**

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

Source: IESO

Class B

Month (¢/kWh)	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JULY 2019	AUG 2019	SEP 2019	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	2020 YTD.
HOEP*	2.78	2.79	2.73	1.56	0.76	0.48	2.19	1.61	1.43	0.72	2.07	2.19	1.48	1.45	1.39	1.44
Class B Global Adjustment Rate	8.09	8.81	8.04	12.33	12.60	13.73	9.65	12.61	12.26	13.68	9.95	9.32	10.23	11.33	11.94	11.14
Total Cost of Commodity	**10.87**	**11.60**	**10.77**	**13.89**	**13.36**	**14.21**	**11.84**	**14.22**	**13.69**	**14.4**	**12.02**	**11.51**	**14.4**	**12.02**	**11.51**	**12.58**

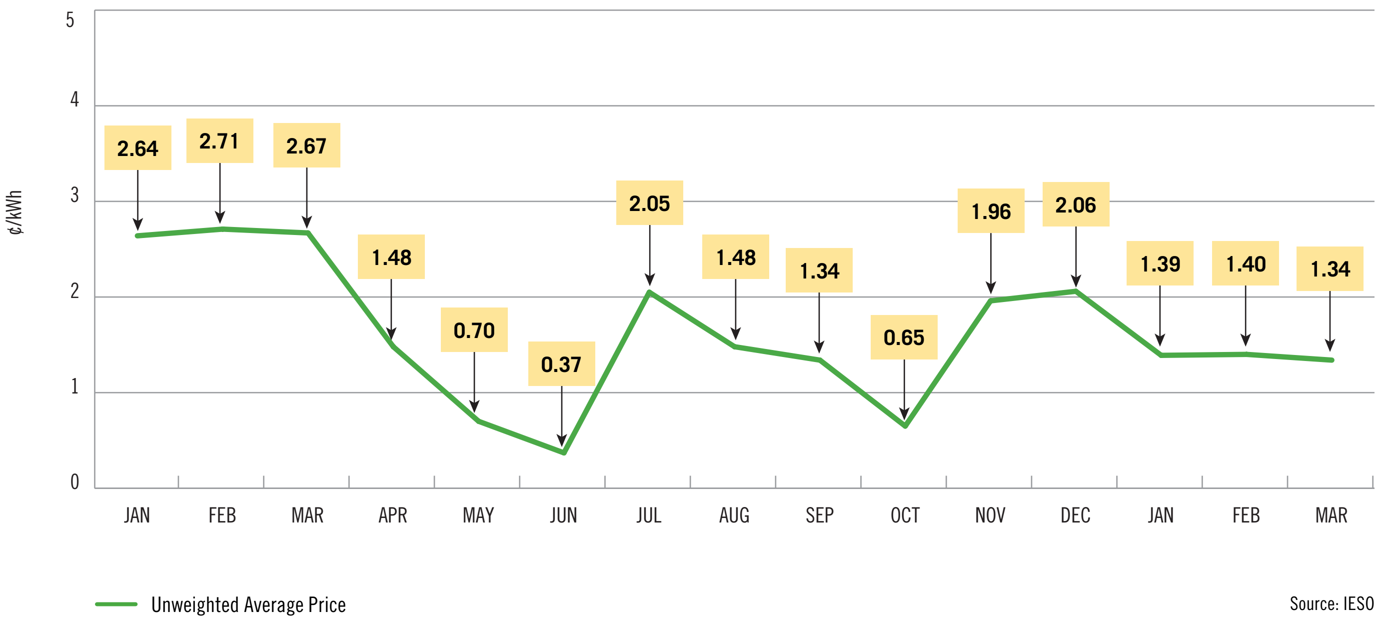
*Averages are weighted by the amount of electricity used throughout the province within each hour to broadly reflect the consumption profile of Class B (i.e., residential and commercial) consumers.

Source: IESO

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

Monthly Wholesale Electricity Prices

The wholesale electricity price fluctuates by the hour. This chart shows the 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.



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

In accordance with the mandate provided under the Ontario Energy Board Act, 1998, the OEB developed the Regulated Price Plan (RPP), which provides residential and small business consumers with stable and predictable electricity pricing and encourages conservation. The plan has been in place since 2005.

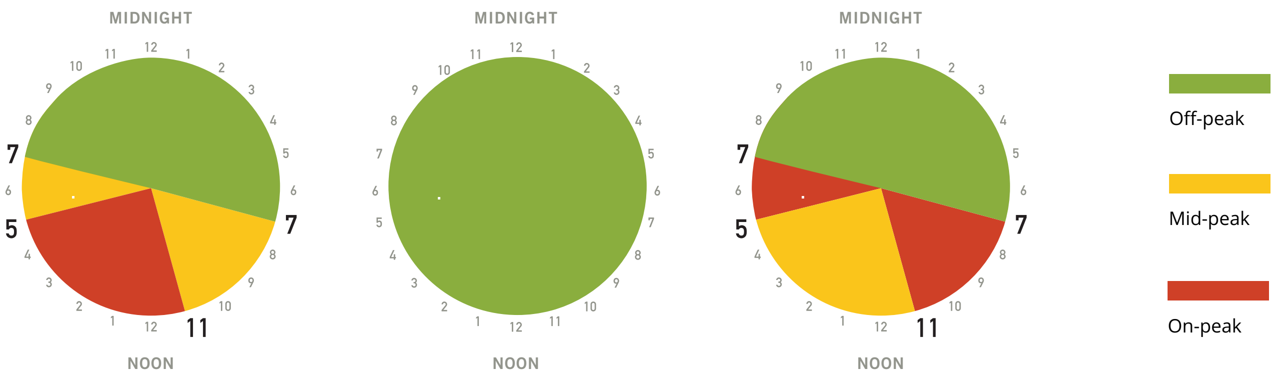
RPP consumers with eligible time-of-use (or "smart") meters that can determine when electricity is consumed during the day pay RPP prices under a time-of-use price structure. The prices for this plan are based on three time-of-use periods per weekday. These periods are referred to as off-peak, mid-peak 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 reflect energy consumption patterns in those seasons, as explained below.

Effective November 1, 2019, the OEB resumed setting RPP prices under section 79.16 of Ontario Energy Board Act, 1998. At the same time, the Ontario government also introduced the Ontario Electricity Rebate, providing a 31.8% rebate on the pre-HST amount of the bill, largely offsetting the RPP price changes on the Electricity line.

On March 17, 2020, the Government of Ontario declared a state of emergency under the Emergency Management and Civil Protection Act to help fight the spread of COVID-19. On March 24, 2020, the Government issued an Emergency Order under the Emergency Management and Civil Protection Act, fixing time-of-use prices at the off-peak price of 10.1 ¢/kWh for all hours of the day, seven days a week. This pricing was in effect until May 31, 2020. The prices below reflect the RPP prices that were set November 1, 2019, and effective for most of the Q1 reporting period.

Summer and Winter Time-of-Use Hours

The RPP time-of-use periods are different in the summer than they are in the winter to reflect seasonal variations in how customers use electricity. During the summer, people use more electricity during the hottest part of the day, when air conditioners are running on high. In the winter, with less daylight, electricity use peaks twice: once when people wake up in the morning and turn on their lights and appliances, and again when people get home from work. The time-of-use (TOU) prices applicable from January 1, 2020 for RPP consumers with eligible time-of-use meters are shown in the table below.



Summer
(May 1 – October 31)
Weekdays

Weekends and Statutory Holidays

Winter
(November 1 – April 30)
Weekdays

Source: OEB

RPP Time-of-use prices effective November 1, 2019

Time-of-use RPP Prices – ¢/kWh	Off-Peak	Mid-Peak	On-Peak	Average Price
Price (¢)	10.1	14.4	20.8	12.8

Sample Residential Monthly Bill

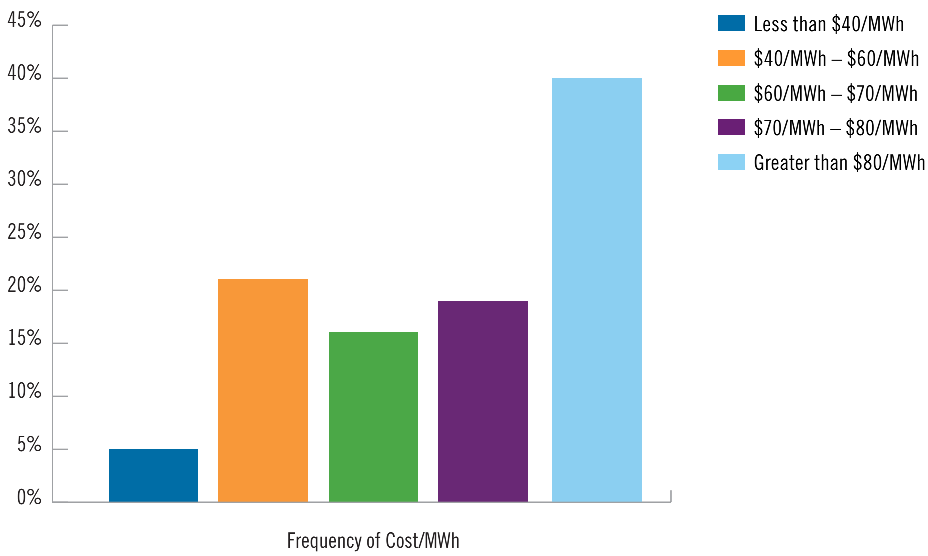
January 1, 2020, w/ w.a. delivery	$/700 kwh
Electricity	89.62
Delivery *OEB calculated w.a. delivery*	42.52
Losses	4.55
Regulatory	3.12
HST	18.18
Ontario Electricity Rebate	(44.46)
Total Bill:	**113.53**

This table shows a monthly bill for a residential RPP TOU consumer with monthly usage of 700 kWh with 64% of consumption occurring off-peak, 18% occurring mid-peak and 18% occurring on-peak. The delivery and regulatory charges are weighted-average charges as calculated by the Ontario Energy Board (OEB). Line losses are based on the weighted-average loss factor as calculated by the OEB. Delivery charges and line losses will vary depending on utility. For additional information please see the OEB's bill calculator: oeb.ca/consumer-protection/energy-contracts/bill-calculator.

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 2019. 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 consumer 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 Rates[2] (2019)



The table below shows average all-in electricity price for a distribution-connected industrial consumer in several service territories.[3]

Distribution-Connected Industrial Rates (2020)

$/MWh	Windsor (EnWin)	Hamilton (Alectra)	Ottawa	Sudbury	Toronto*
HOEP**	13.84	13.86	13.87	14.38	13.88
Class A Global Adjustment	59.93	60.02	60.03	62.25	60.08
Delivery	11.38	20.27	20.10	14.87	23.94
Regulatory	3.92	3.92	3.92	4.07	3.93
All-In Price	**89.07**	**98.07**	**97.92**	**95.57**	**101.83**

* The distribution cost estimate for an industrial customer in Toronto reflects the assumption that 1kVA is 1 kW for billing purposes.
** HOEP is based on a three-month arithmetic average (January - March 31, 2020). The Global Adjustment shown in the table is an average of all distribution-connected Class A consumers for January to March 2020. Both quantities have been adjusted for losses using the applicable primary metered loss factor for each distributor.

Source: IESO and OEB

Note: The Debt Retirement Charge ended for all electricity users on March 31, 2018.

2 Does not include Northern Industrial Electricity Rate Program.
3 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 2017. 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.

2019 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 April 2019. 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
1	Quebec	5.79
2	Manitoba	5.87
3	Oklahoma	6.09
4	Washington	6.18
5	Ontario North	6.84
6	Texas	6.83
7	Nevada	6.92
8	Kentucky	6.93
9	Georgia	7.19
10	Louisiana	7.19
11	New York	7.29
12	Iowa	7.37
13	Utah	7.39
14	Tennessee	7.50
15	North Carolina	7.54
16	South Carolina	7.54
17	Idaho	7.54
18	Arkansas	7.55
19	Montana	7.67
20	New Mexico	7.70
21	West Virginia	8.04
22	Mississippi	8.07
23	Arizona	8.08
24	Missouri	8.14
25	Alabama	8.24
26	Oregon	8.37
27	Ohio	8.38
28	British Columbia	8.51
29	Wyoming	8.58
30	Pennsylvania	8.69
31	New Brunswick	8.74
32	Newfoundland	8.82
33	Ontario South	8.84
34	Illinois	8.95
35	**Canadian Average**	**9.03**
36	Virginia	9.22
37	Kansas	9.56
38	Colorado	9.57
39	Michigan	9.60
40	Saskatchewan	9.62
41	Indiana	10.04
42	Nebraska	10.06
43	South Dakota	10.15
44	Florida	10.15
45	Wisconsin	10.17
46	Prince Edward Island	10.24
47	Maryland	10.25
48	Minnesota	10.36
49	Delaware	10.44
50	**U.S. Average**	**10.58**
51	Nova Scotia	11.02
52	North Dakota	11.18
53	District of Columbia	11.28
54	Alberta	12.87
55	Maine	12.98
56	New Jersey	13.54
57	Vermont	13.95
58	California	14.68
59	New Hampshire	17.37
60	Connecticut	18.88
61	Massachusetts	19.17
62	Rhode Island	21.17
63	Alaska	24.45
64	Hawaii	35.52

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

The Ontario price is based on April 2019 data and includes the Hourly Ontario Energy Price, Class A Global Adjustment, delivery, and wholesale market service charges.

All other Canadian prices are from the Hydro Quebec Rate Comparison for rates effective April 1, 2019 for select local distribution companies servicing specific cities and reflects a 5 MW consumer with an 65% load factor. 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.

American jurisdictions reflect April 2019 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 = 1.34 CAD.

Electricity – What's New

A collection of electricity reports and publications.

Information	Published By	Date
Reliability Outlook	IESO	June 20, 2019
Quarterly Conservation Report (Q2 & Q3 2019)	IESO	November 21, 2019
Progress Report on Contracted Electricity Supply (Q4 2019)	IESO	March 24, 2020
Pickering Performance Report – Q1 2020	OPG	June 16, 2019
Darlington Performance Report – Q1 2020	OPG	June 16, 2020
OPG Quarterly Financial Results – Q1 2020	OPG	May 12, 2020
Darlington Refurbishment Performance Report – Q1 2020	OPG	May 12, 2020
Power News – Special Edition – COVID-19	OPG	April 24, 2020
Hydro One Quarterly Report (Q4 2019)	Hydro One	August 9, 2019
Report on the 2018 Results of LEAP Emergency Financial Assistance	OEB	January 13, 2020
Final Staff Report to the Board, Consultation to Review Natural Gas Supply Plans	OEB	March 26, 2020

* The complete Refurb reports are no longer being posted to OPG.com. An update report is being posted instead.