Ontario Demand Forecast

DECEMBER 19, 2019

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Executive Summary

The IESO is responsible for forecasting electricity demand in Ontario and for assessing whether transmission and generation facilities are adequate to meet Ontario's needs. This document presents the electricity demand forecast for the period from January 2020 to June 2021 and supersedes the previous forecast released in September 2019.

Economic Outlook

The Ontario economy showed solid growth throughout 2019 and is expected to have the strongest job growth (2.7%) since 2003. Of particulate note is that job growth has strengthened throughout the year, boding well for 2020. Although strong, the numbers do hide the fact that the manufacturing sector will shed jobs in 2019, as the sector both started and will be ending the year with job losses. As such, the robust job growth did not translate into higher electricity demand as manufacturing employment is most closely correlated to electricity demand. Other than the poor showing from manufacturing, job growth is fairly healthy across the remaining sectors with the exclusion of utilities. As well, the split between full- and part-time employment is balanced (2.6% versus 4.3%).

The province continues to enjoy a strong economic environment - low interest rates, a relatively low Canadian dollar and strong U.S. growth – that should continue to foster further growth. One of the major risks moving forward centres around trade disruption. There has been significant improvement on that front just recently with the pending ratification of the Canada-United States-Mexico Agreement (CUSMA) and the prospect of an agreement to end the current U.S. – China trade war.

Looking forward, Ontario has some economic challenges. Despite strong job growth in 2019, consumer spending has lagged due to debt loads and housing costs. An interest rate increase would further reduce consumption, the largest part of the economy. As well, both the UK and U.S. – the two top destinations for Ontario's exports – are forecasted to see more moderate growth in 2020. Assuming that the trade risks will be alleviated in the near term, the big risks centre on interest rates and debt.

On a more local level a variety of different stories are being written. The boom in the greenhouse sector has had a direct impact on employment in the agriculture sector and on electricity demand due to lighting requirements. This has a positive impact in the Niagara and Leamington areas. Conversely, the Oshawa General Motors plant is winding down vehicle production to shift to aftermarket parts production. This will have a negative impact throughout the local economy. Although modest economic and employment growth is projected for the province in 2020 and 2021, regional outcomes will vary.

Actual Weather and Demand

Since the last Ontario Demand Forecast document was published, actual demand figures for the six months of June - November have been recorded, and demand was significantly lower than the same months a year ago. Actual demand was down 3.8% compared to a year ago but has shown a more modest decline of 1.7% after adjusting for the variance in weather.

During the same time period, distributor loads decreased by 3.9 percent year over year – after adjusting for weather, the year-over-year change was a decrease of 1.7 percent. Embedded generation output for the six months did increase by 5.2% over the same period a year earlier. Taking into account the weather variation and the increased output in embedded generation, distributors loads declined by 1.1 percent compared to a year ago.

Wholesale customers' consumption decreased by 2.6 percent against 2018, as well as against the same months from 2017. The 'Big Six' industrial sectors showed a more modest decline of 1.7 percent for the six months. The Big Six sectors account for over 85 percent of wholesale customers loads. Mining is the largest sector and experienced growth of 0.9 percent. The next largest sector, Iron & Steel, had declines of 2.6 percent. The remaining sectors (in order of consumption) had mixed results; Pulp & Paper decreased 11.1 percent, Chemicals grew by 6.8 percent, Petroleum processing declined 3.6 percent and Transportation Equipment decreased by 2.9 percent.

Peak demand for the summer of 2019 occurred in July. The summer peak was 21,791 MW and was only slightly higher than the summers peaks of 2017 (21,786 MW) and 2014 (21,363). Both those years were winter peaking as the summers were colder than normal. The weather corrected peak was 22,100 MW and fell in August. Once again, this was higher than the values for the summer of 2014 and 2017 and very similar to last year's weather corrected peak of 22,107 MW. There were some Industrial Conservation Initiative (ICI) impacts on the peak day, as Class A customers hedged against the peak falling in the top five peaks. The fall peak is generally a warm weather peak occurring in September. Despite not having the hot September like the past two years, the fall peak still occurred in September (19,717 MW) which was slightly higher than the cold weather peak in November (19,625 MW). After correcting for weather, the warm weather peak holds for the season.

The weather over the course of the summer was near the 31-year Normal Weather scenario. Whereas June was consistently milder than normal, July was consistently warmer than normal and August had days on both sides. The fall was colder than normal due to a significantly colder-than-normal November. Overall, embedded generation for the summer and fall was 5.2 percent higher than the same period a year ago, owing to higher wind (26.3%) and hydro (32.4%) output.

Demand Forecast

In the Reliability Outlook, the impacts of conservation, embedded generation and prices are incorporated into the demand forecast, resulting in reduced demand. Conversely, demand-response programs are included in this analysis as a resource under the category of demand measures. Load modifiers – conservation, embedded generation and prices – and demand measures are discussed in section 4.4 of this document.

Table 1 summarizes the annual peak and energy demand forecast for the period covered in this 18-month forecast. Summer and winter peaks are expected to increase over the forecast, as conservation savings and increased embedded output have levelled off and are more than offset by the factors pushing up growth in end-uses.

Grid-supplied energy demand is expected to dip in 2019, as some of the weakness in the latter half of 2018 carried over into 2019. For 2020, demand is expected to see positive gains beyond the bump that comes with the additional day of a leap year. Continued economic and demographic growth will push demand higher.

Table 1: Peak and Energy Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2019-20	21,185	22,353
Summer 2020	22,194	24,555
Winter 2020-21	21,239	22,533

Year	Normal Weather Energy (TWh)	% Growth in Energy
2009	140.4	-5.7%
2010	142.1	1.2%
2011	141.2	-0.6%
2012	141.3	0.1%
2013	140.5	-0.6%
2014	138.9	-1.1%
2015	136.2	-1.9%
2016	136.2	0.0%
2017	132.3	-2.8%
2018	135.2	2.1%
2019 (Forecast)	134.4	-0.8%
2020 (Forecast)	136.4	1.7%

- End of Section –

Caution and Disclaimer

Contents

List of Tables

List of Figures

1. Introduction

1.1 Outlook Documents

The Market Rules for the Ontario Electricity Market (Chapter 5 Section 7.1) require the IESO to prepare and publish a demand forecast for the next 18 months on a quarterly basis. This Ontario Demand Forecast meets that requirement and covers the period from January 2020 to June 2021. It supersedes the previous forecast released in September 2019 and the previous Ontario Demand Forecast released in June 2019.

1.2 Demand Forecast Document

This document provides an 18-month forecast of electricity demand for Ontario, based on the stated assumptions and using the methodology described in the "Methodology to Perform Long-Term Assessments," found on the IESO website at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2019dec.pdf. Readers may envision other scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgment in considering possible future scenarios. This forecast provides a base upon which changes in assumptions can be considered.

Ontario demand is the sum of coincident loads plus the losses on the IESO-controlled grid. This demand forecast was based on actual demand, weather and economic data through the end of September 2019. Data for October and November have been incorporated into the tables and figures of this document. This document is divided into the following sections:

Section 2.0 summarizes the forecast results.

Section 3.0 looks at historical demand.

Section 4.0 describes the assumptions used in this forecast of electricity demand.

All the tables in this report are contained in the Reliability Outlook Tables (http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlooktables_2019dec.xls) spreadsheet posted alongside the Outlook documents. The spreadsheet's historical tables contain data going back to market opening, which would not be practical in a printed document.

Readers are invited to provide comments or suggestions regarding the content of this or future reports. To do so, please call IESO Customer Relations at 905-403-6900 or 1-888-448-7777 or send an email to customer.relations@ieso.ca.

Electronic copies of the forecast are available upon request.

- End of Section -

2. Demand Forecast

This section presents the demand forecast for the Outlook period. Additional tables are included in the Reliability Outlook Tables spreadsheet.

Table 2-1 contains the forecast of system weekly peak, energy demand and the load forecast uncertainty (LFU) for the weekly peak. The LFU is a measure of variability in load due to the volatility of weather. Figures 2.1 and 2.2 show historical weekly energy and peak demand along with the projected forecast.

Table 2-1: Weekly Peak and Energy Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
05-Jan-20	19,918	20,913	570	2,766
12-Jan-20	21,185	22,353	547	2,923
19-Jan-20	20,757	21,385	483	2,899
26-Jan-20	20,618	21,568	404	2,899
02-Feb-20	20,637	21,718	734	2,915
09-Feb-20	19,917	21,508	635	2,851
16-Feb-20	19,555	20,902	581	2,783
23-Feb-20	19,310	20,967	501	2,750
01-Mar-20	19,830	21,014	531	2,794
08-Mar-20	19,377	20,150	649	2,726
15-Mar-20	18,274	18,933	611	2,637
22-Mar-20	17,606	18,507	569	2,530
29-Mar-20	17,592	18,560	567	2,538
05-Apr-20	17,323	17,873	471	2,496
12-Apr-20	16,671	17,541	496	2,385
19-Apr-20	16,044	16,204	531	2,367
26-Apr-20	16,236	16,767	721	2,362
03-May-20	17,268	19,567	849	2,344
10-May-20	16,551	19,296	845	2,349
17-May-20	18,057	21,149	1,175	2,370
24-May-20	17,705	21,392	1,330	2,322
31-May-20	18,533	20,855	1,292	2,385

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Table 2-1 - continued

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
07-Jun-20	19,261	23,379	1,055	2,559
14-Jun-20	20,335	23,772	835	2,576
21-Jun-20	21,401	23,839	754	2,639
28-Jun-20	21,530	23,846	1,016	2,695
05-Jul-20	20,535	23,291	814	2,655
12-Jul-20	22,194	24,555	838	2,759
19-Jul-20	20,743	24,051	1,035	2,629
26-Jul-20	21,290	24,252	841	2,720
02-Aug-20	21,944	24,100	958	2,717
09-Aug-20	21,289	23,693	985	2,683
16-Aug-20	20,532	23,504	1,362	2,665
23-Aug-20	21,375	23,147	1,413	2,711
30-Aug-20	19,979	22,399	1,370	2,560
06-Sep-20	18,388	23,201	680	2,451
13-Sep-20	18,845	20,551	781	2,427
20-Sep-20	17,616	19,795	420	2,432
27-Sep-20	16,847	18,117	554	2,371
04-Oct-20	17,175	17,204	786	2,417
11-Oct-20	16,806	16,863	507	2,434
18-Oct-20	17,107	17,518	392	2,395
25-Oct-20	17,286	17,783	318	2,477
01-Nov-20	17,545	18,172	416	2,505
08-Nov-20	18,538	18,858	601	2,586
15-Nov-20	18,683	19,396	342	2,606
22-Nov-20	19,233	19,915	607	2,678
29-Nov-20	19,646	21,100	409	2,740
06-Dec-20	19,949	20,956	555	2,767
13-Dec-20	20,341	21,304	690	2,809
20-Dec-20	20,059	21,135	362	2,796
27-Dec-20	18,804	20,651	528	2,753
03-Jan-21	20,243	21,138	528	2,742

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Table 2-1 - continued

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
10-Jan-21	21,239	22,533	570	2,949
17-Jan-21	20,902	21,827	547	2,921
24-Jan-21	20,760	21,910	483	2,921
31-Jan-21	20,779	22,061	404	2,945
07-Feb-21	20,256	21,644	734	2,872
14-Feb-21	19,890	21,240	635	2,804
21-Feb-21	19,649	21,306	581	2,771
28-Feb-21	20,182	21,367	501	2,823
07-Mar-21	19,742	20,314	531	2,755
14-Mar-21	19,082	19,541	649	2,686
21-Mar-21	17,939	18,636	611	2,562
28-Mar-21	17,926	18,695	569	2,559
04-Apr-21	17,953	18,283	567	2,486
11-Apr-21	17,023	17,894	471	2,437
18-Apr-21	16,559	16,653	496	2,399
25-Apr-21	16,581	16,909	531	2,384
02-May-21	17,613	19,913	721	2,368
09-May-21	16,692	19,640	849	2,371
16-May-21	18,198	21,491	845	2,397
23-May-21	17,845	21,733	1,175	2,396
30-May-21	18,681	21,199	1,330	2,354
06-Jun-21	19,408	23,623	1,292	2,571
13-Jun-21	20,485	23,920	1,055	2,598
20-Jun-21	21,537	23,878	835	2,661
27-Jun-21	21,981	23,995	754	2,717
04-Jul-21	21,922	24,568	1,016	2,678

Figure 2.1: Weekly Energy Demand – History and Forecast

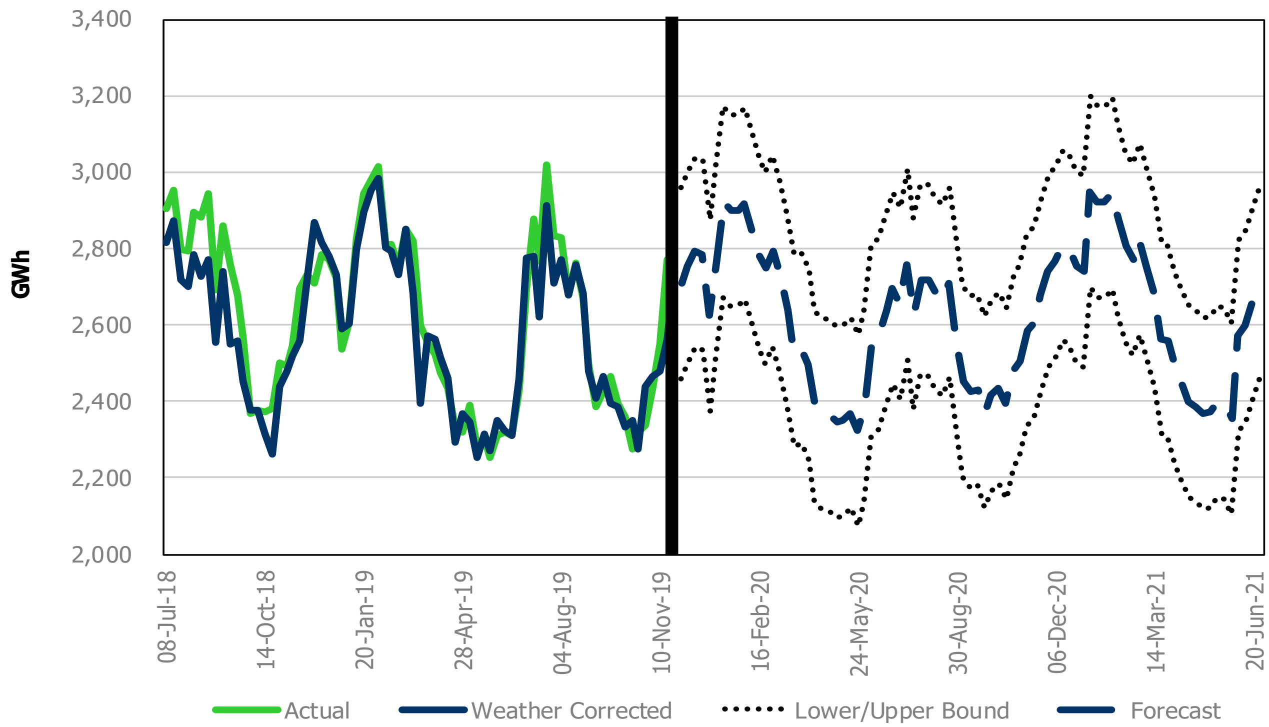
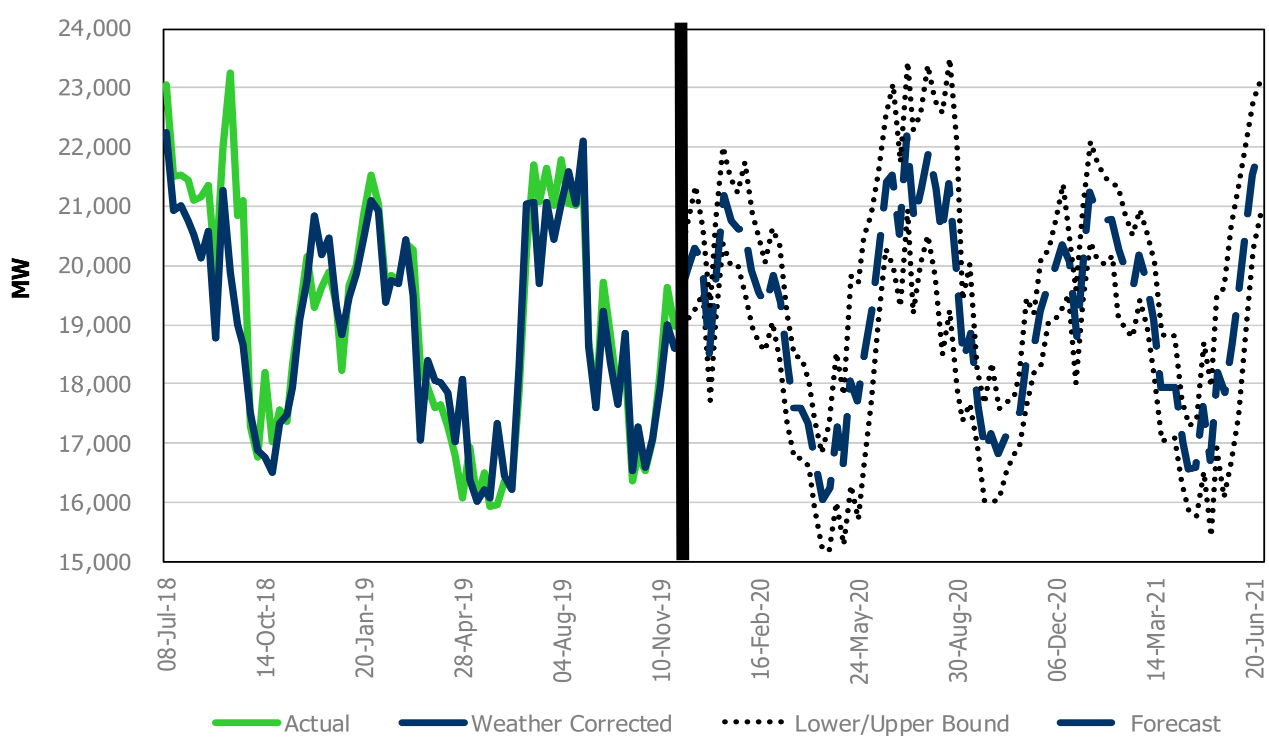


Figure 2.2: Weekly Peak Demand – History and Forecast



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3. Historical Review

This section discusses historical electricity demand. The weather-corrected numbers are generated based on normal weather.

3.1 Six-Month Review – June to November

Since the last Ontario Demand Forecast document, actuals have been recorded for the period June to November 2019. The summer of 2019 was near normal and the fall of 2019 was colder than normal. For the summer, August and June pushed summer temperatures lower, while the fall was driven by an extremely cold November.

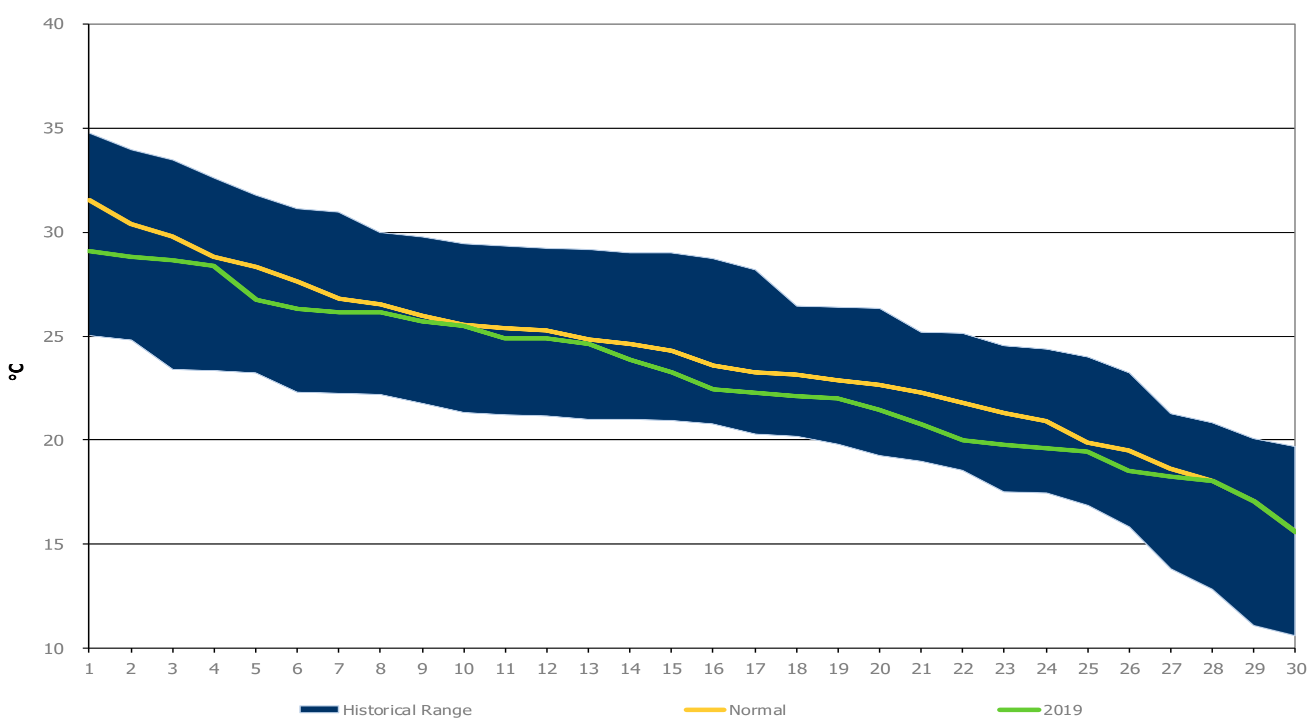
The actual summer peak occurred in July (21,791 MW) and the weather-corrected peak occurred in August (22,100 MW weather-corrected). The fall peak occurred in September (19,717 MW and 19,244 MW weather-corrected). The fall peak is either driven by cold temperatures in November or warm temperatures in September as the fall is a transition season. This year, the warm weather September peak (19,717 MW) and the cold weather November (19,625 MW) peak were very close.

Following is a month-by-month look at demand and weather.

June

In June, the weather was colder than normal, with average temperatures putting it in the coldest quartile of the past 50 years. The peak temperature for the month was also in the coldest quartile.

Figure 3.1: Daily Temperature - June



The monthly peak (20,248 MW) occurred on Thursday, June 27, the hottest day of the month. The afternoon high was 28.9°C (at Toronto), the coolest June peak since 2015, when the peak (19,339 MW) was the lowest since market opening.

The weather-corrected peak for the month was 21,043 MW. This is consistent with post-2009 recession weather-corrected peaks, which have averaged 21,200 MW.

Energy demand for the month was 10.4 TWh (10.5 TWh weather-corrected), lower than the last several years, which averaged roughly 11.0 TWh weather-corrected.

The minimum demand for the month was 10,564 MW, in line with June values since the 2009 recession. The minimum occurred in the early hours of Sunday, June 9.

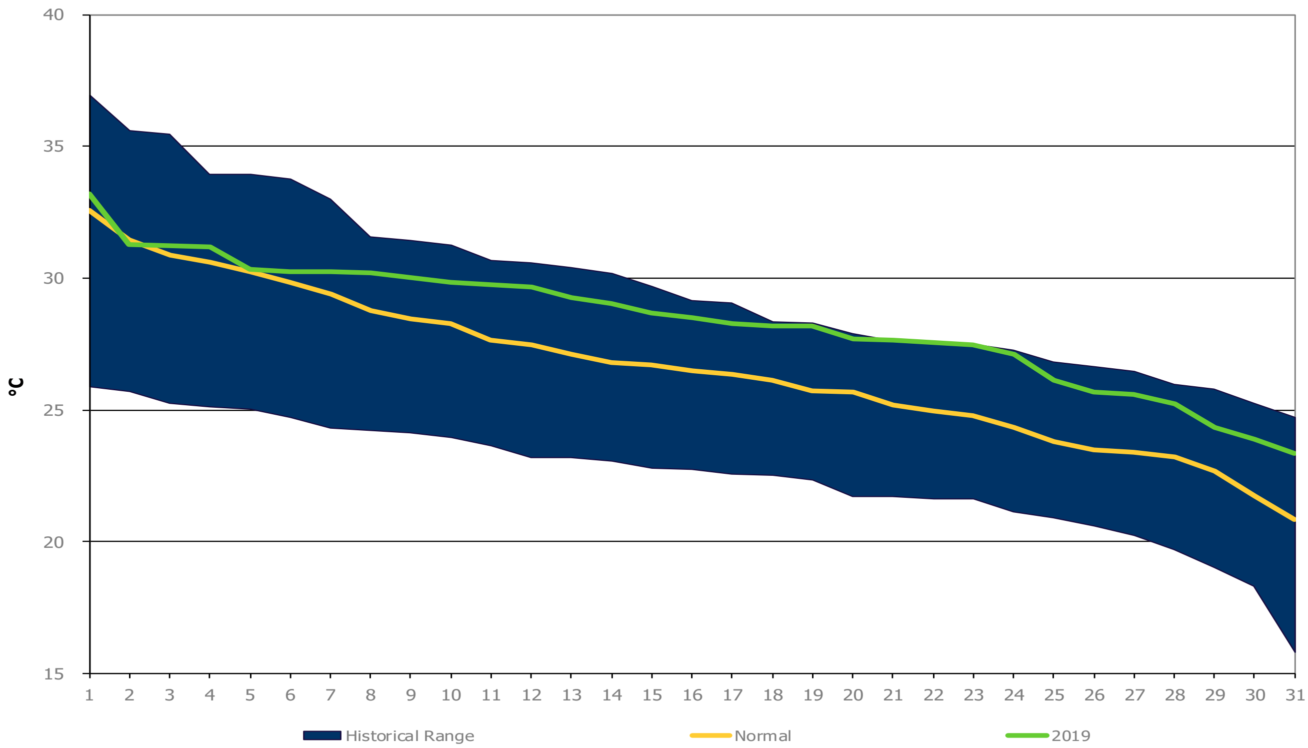
Embedded generation for the month was 602 GWh, an increase of 0.1 percent compared to the previous June. Hydro (27.6%) and non-contracted (94.4%) output were up, but reductions in solar (-9.1%) and bio (-6.5%) output offset those increases.

Wholesale customer consumption increased 0.9 percent year over year. Most of the growth came from petroleum refining (45.2%) and chemicals (2.6%). Other major sectors were flat.

July

This year, the weather was warmer than normal for July. The warmer weather didn’t occur during peak periods, but instead over the remainder of the month when the weather is usually cooler. The peak temperature was the 18th highest over the past 50 years, but the average temperature was the seventh highest.

Figure 3.2: Daily Temperature – July



The peak occurred on July 29, the third warmest day of the month, during a modest heat wave. The peak-day high was 31.4°C, which was slightly warmer than normal. The actual peak was 21,791 MW (21,069 MW weather-corrected). The observed July peak was the fourth-lowest since market opening.

Similar to last July, energy demand for the month was 12.7 TWh (12.3 TWh weather-corrected)

Minimum demand was 11,565 MW – a high value by recent historical standards – and occurred in the early morning of the Canada Day holiday.

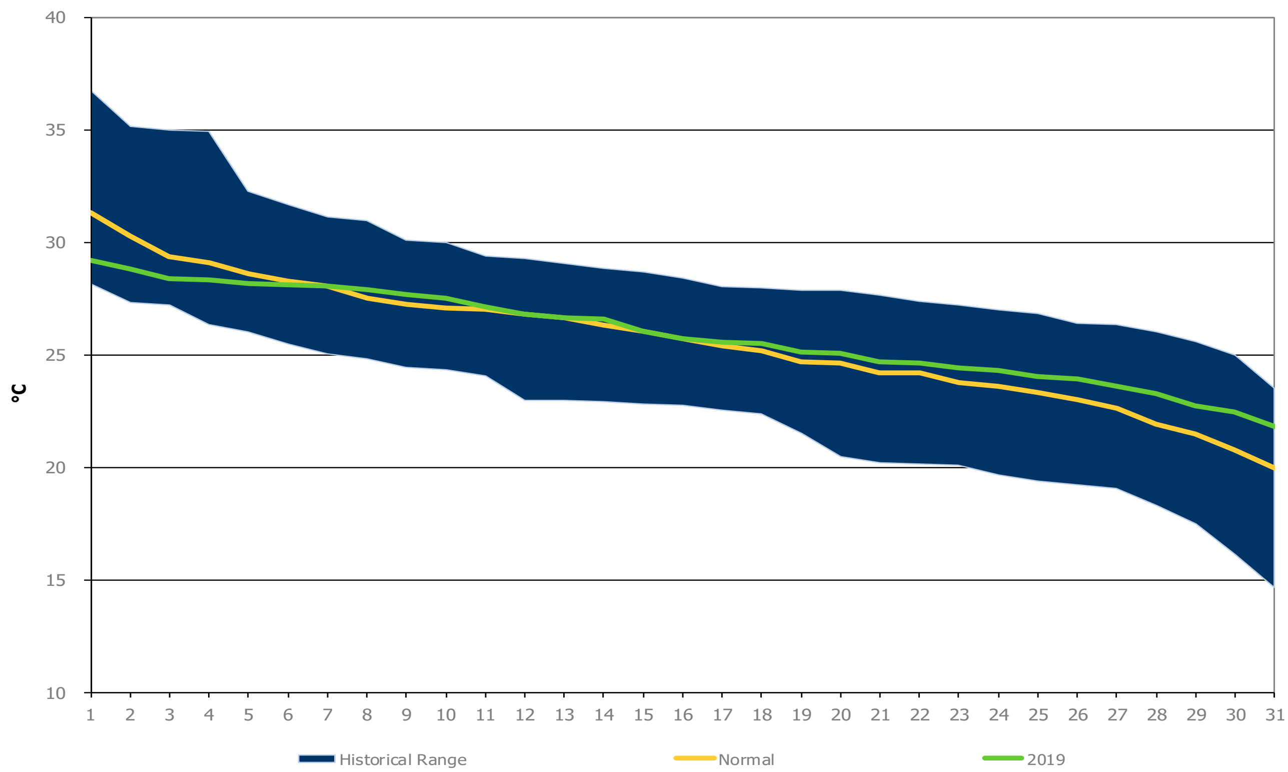
Embedded generation for July topped 607 GWh, which represents a 20.1 percent increase over last July. Bio-gas output was down slightly (-1.3%) over the previous July, while all other types– solar (2.4%), wind (12.6%) and hydro (24.2%) – increased.

Wholesale customer load fell 0.4 percent year over year. While iron and steel (4.5%) rebounded with the removal of U.S. tariffs, and petroleum refining (0.3%) and chemicals (4.3%) continued to perform strongly, declines in pulp and paper (-9.3%) and other sectors brought the numbers down for the month.

August

This year, the weather for August was near normal. Although average temperatures were representative, peak temperatures were cooler than normal and minimum temperatures were higher than normal. This means that energy demand was typical but peak demand was low. The peak temperature was the 45th highest over the past 50 years, while the average temperature was the 26th highest.

Figure 3.3: Daily Temperature - August



Peak demand occurred on August 21, which was the hottest day of the month and came at the end of a moderate heat wave. The peak-day high was 30.2°C, which was cooler than normal. The actual peak was 21,354 MW (22,100 MW weather-corrected).

Without the high temperatures of last year, actual demand was 11.8 TWh, much lower than last year's 12.7 TWh. With near-normal average temperatures, the weather-corrected value was also 11.8 TWh.

Minimum demand was 11,280 MW and occurred in the early morning of Sunday, August 11.

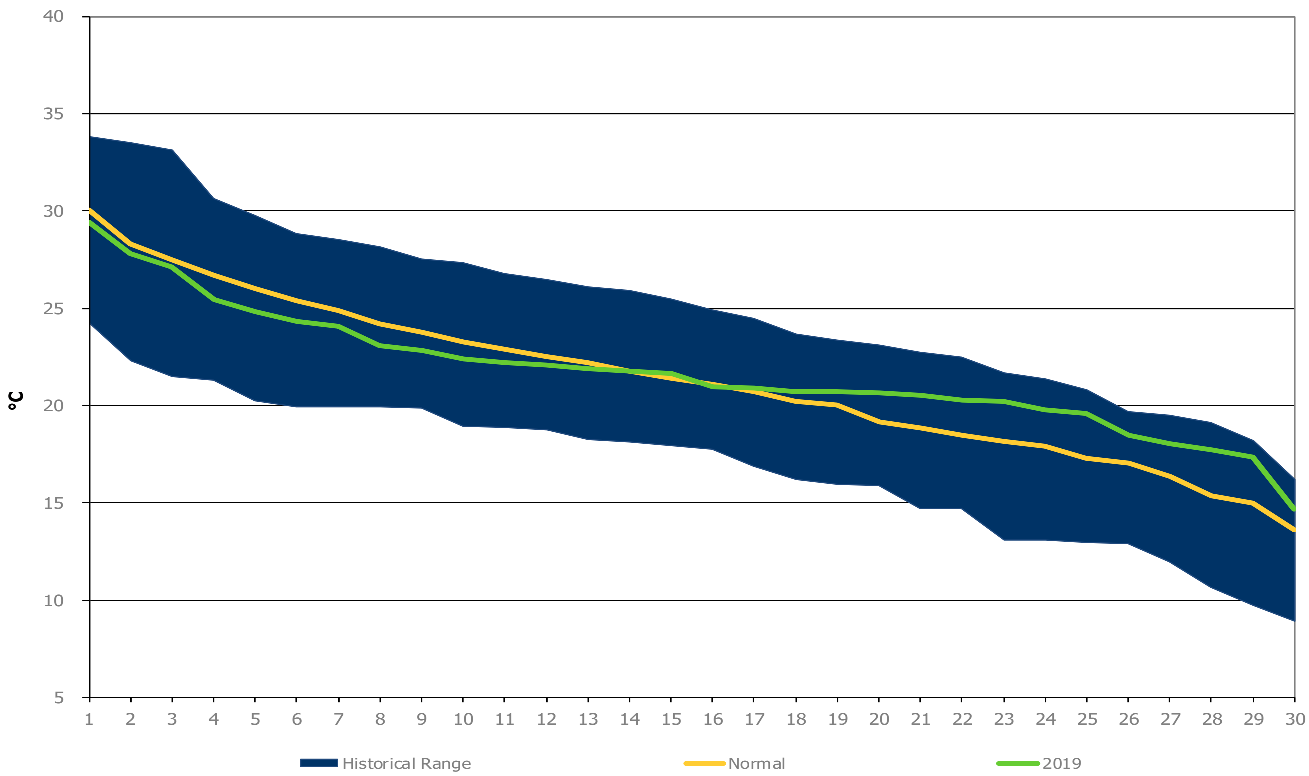
Embedded generation for August topped 557 GWh, representing a 6.7 percent increase over last August. Increases in wind (28.5%) and hydro (39.0%) output more than offset the decline in solar (-4.9%) and bio-gas (-5.5%) output.

Wholesale customer load fell slightly (-0.1%) in August. Pulp and paper (-9.3%) and iron and steel (-8.6%) showed declines that outweighed growth in mining (10.4%) and chemicals (3.1%). At this point, wholesale customer load continues to bounce around without a clear and sustained pattern.

September

The weather for September was near normal in both average and peak demand temperatures.

Figure 3.4: Daily Temperature - September



The monthly peak occurred on Wednesday September 11, the second hottest day of the month. There was a warmer set of days in the month, but those spanned a weekend and therefore didn't deliver a monthly peak. The afternoon high was 28.6°C (at Toronto), which is the mildest September peak since 2012. The peak was 19,717 MW and 19,244 MW weather-corrected.

Energy demand for the month was 10.3 TWh (10.3 TWh weather corrected) which is the lowest September actual since market opening.

The minimum demand for the month was 10,477 MW, and occurred in the early hours of September 29. This is the lowest September minimum since market opening.

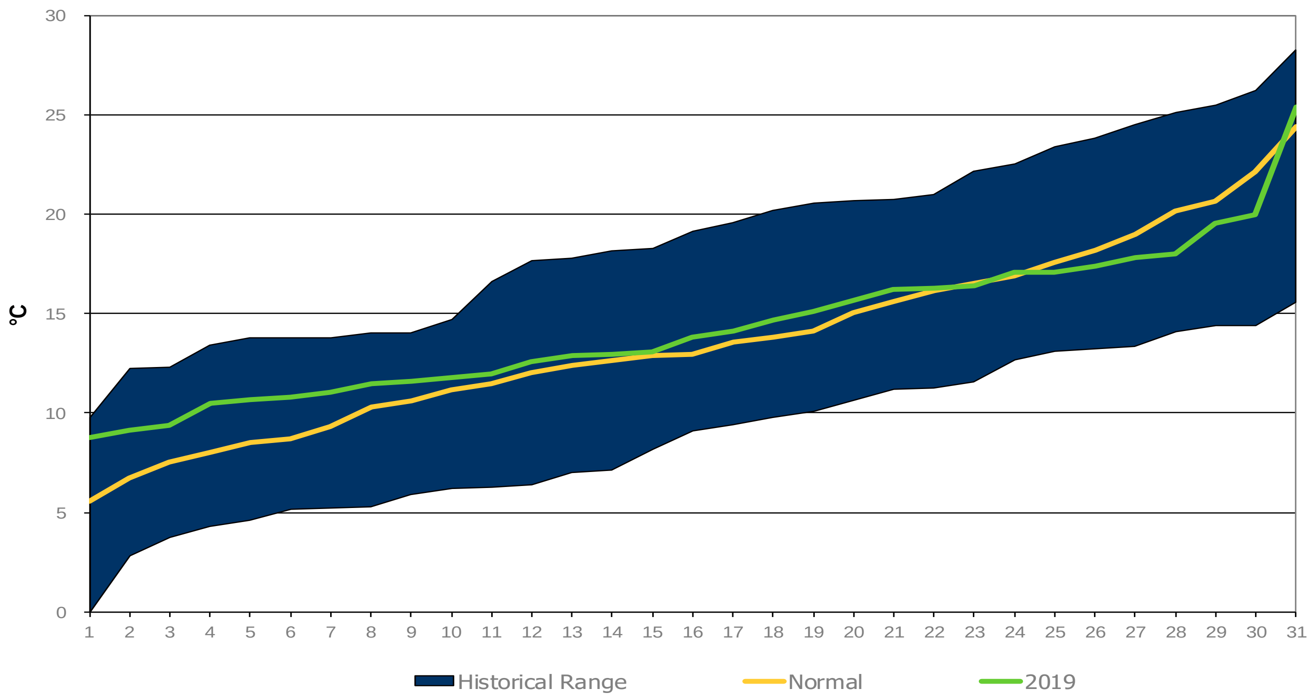
Embedded generation for the month was 484 GWh, virtually the same as the previous year.

Wholesale customers' consumption dropped 5.9 percent compared to September 2018 and represented the largest monthly decline since September 2017. Declines in mining (-5.3%), pulp and paper (-16.3%) and refining (-27.3%) more than offset gains in the chemicals (14.6%) and iron and steel (5.2%) sectors.

October

The weather for October was milder than typically expected. The month was not warm but lacked cold temperatures. This October, the peak was driven by hot weather.

Figure 3.5: Daily Temperature - October



The peak for October occurred on the first of the month when daytime highs reached 31.2 °C (Toronto). Peak demand reached 18,329 MW, the highest October value since 2013. The weather-corrected value (18,652 MW) was also the highest since 2013.

Energy demand for the month was 10.3 TWh, which is low by historical standards. This is due to mild weather for the month. After adjusting for weather, energy demand for the month came in at 10.6 TWh, which is in line with recent experience.

The minimum demand for the month was 10,739 MW and occurred during the early hours of Sunday, October 6. That Sunday was the second warmest day of the month, leading to the dip in demand as October is generally a heating month.

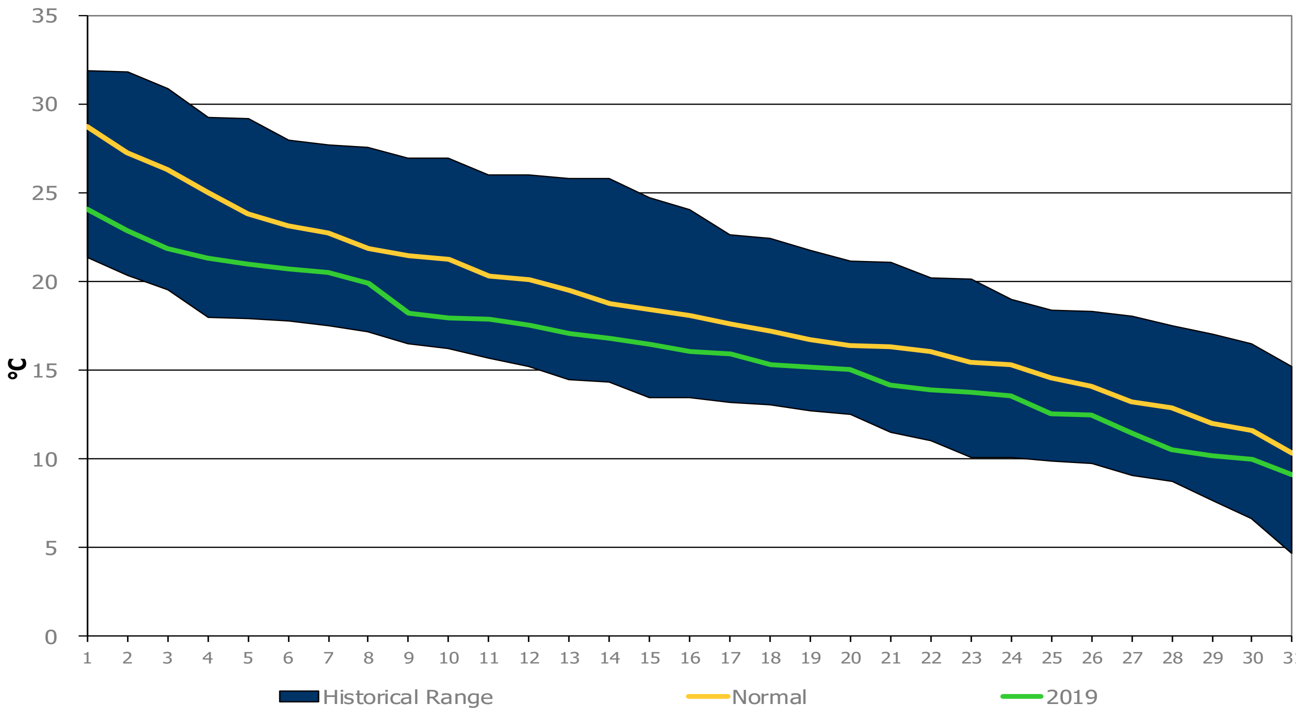
Embedded generation for the month was 506 GWh, a 3.8 percent increase over the previous year. Higher embedded hydro and wind output accounted for the growth as solar output was down significantly (-22.0%).

Wholesale customers' demand fell by 4.4 percent compared to the previous October. This makes four consecutive months of decline and will demand monitoring going forward to gauge whether this is a temporary cycle or the start of a trend. Pulp and paper, petrochemicals and iron and steel were behind the declines for the month. Mining and basic chemicals showed growth in October.

November

The weather for November was colder than normal. A snowstorm before Remembrance Day marked the unofficial start of winter. The average temperatures for the month rank it as one of the coldest Novembers in the past 50 years (3rd). Figure 3.6 shows how the temperature for November 2019 stacked up against history.

Figure 3.6: Daily Temperature - November



November's peak demand occurred on November 13, the second coldest day of the month. The peak was 19,625 MW (19,001 MW weather-corrected) and was slightly lower than last November's peak – which occurred on a significantly colder day.

Energy demand for the month was 11.3 TWh (10.9 TWh weather-corrected), which was very similar to the November experience since 2014.

Minimum demand for the month was 11,711 MW, which is consistent with the experience of recent years. The minimum occurred in the early hours of Sunday, November 3 when temperatures were mild.

Embedded generation for the month was 453 GWh, a 6.8 percent increase compared to the previous November. Wind (4.2%) and hydro (34.2%) output were up significantly, offsetting a very large decline in solar output (-37.7%).

Wholesale customers' consumption continued the negative trend that began in July. Year-over-year consumption decreased by 4.8 percent with mining (-0.2%) and chemicals (3.9%) as the strongest sectors and refining showing the greatest decline (-20.3%).

Table 3-3.2 of the Reliability Outlook Tables spreadsheet contains monthly demand information going back to market opening.

Table 3-1 contains a summary of the weather and demand for the past six months.

Table 3-1: Historical 2018-19 Weather and Demand Summary

Historical Analysis		June	July	August	September	October	November
Actual Weather	Average Temperature (°C)	22.7	28.0	25.8	21.9	14.5	3.5
	Minimum Temperature (°C)	15.2	23.1	20.9	13.7	8.3	-4.9
	Maximum Temperature (°C)	29.0	32.4	30.2	31.2	31.2	11.7
Normal Weather	Normal Average Temperature (°C)	23.8	26.4	24.4	20.9	12.6	6.7
	Normal Minimum Temperature (°C)	13.4	20.0	18.2	9.5	4.0	-2.0
	Normal Maximum Temperature (°C)	31.3	30.9	30.8	29.8	21.1	18.9
Actual Demand	Peak Demand (MW)	20,248	21,791	21,534	19,717	18,329	19,625
	Average Hour (MW)	14,397	17,195	15,894	14,331	13,913	15,632
	Minimum Hour (MW)	10,564	11,565	11,280	10,477	10,739	11,711
	90th Percentile (MW)	17,337	20,646	19,306	16,722	15,950	17,850
	Percent above 20,000 (MW)	0.4%	19.6%	5.5%	0.0%	0.0%	0.0%
	# of Hours Above 20,000 (MW)	3	146	41	0	-	-
	Energy Demand (GWh)	10,366	12,793	11,825	10,319	10,351	11,255
Weather-Corrected Demand	Peak Demand (MW)	21,043	21,069	22,100	19,244	18,652	19,001
	Energy Demand (GWh)	10,476	12,269	11,806	10,316	10,580	10,908
Forecast Demand	Peak Demand (MW)	21,623	22,061	21,200	19,470	17,559	19,597
	Energy Demand (GWh)	10,939	11,764	11,598	10,564	10,788	11,195

Notes for Table 3-1 – Weather is for Toronto. Temperature is the daily high. Forecast is the most recent for that period.

3.2 Historical Energy Demand

The six-month period can be broken into its two main components – summer (June, July and August) and fall (September, October and November).

The weather over the summer was near normal as both June and August were both below seasonal temperatures. Compared to the previous summer, energy demand was down 3.6 percent; after adjusting for the weather, the decrease was 2.0 percent.

Not surprisingly, distributors' loads followed a similar pattern. For the summer of 2019, they were down 3.9 percent over the previous summer and down 2.1 percent after making weather adjustments. The output of embedded generation (1.77 GWh) was higher than the previous summer (1.66 GWh). Wind output was up 28.5 percent and hydro output increased 39.0 percent over the previous summer. Solar (-4.9%) and biogas (-5.5%) were both down.

For the summer months, wholesale loads showed a decrease of 0.1 percent compared to the previous summer. Mining (3.1%), refining (13.8%), chemicals (3.3%) and vehicle manufacturing (1.0%) showed growth over the summer, while pulp and paper (-11.7%) and iron and steel (-1.8%) showed declines.

For the fall, weather was colder than normal as September and October were near normal, but November was significantly colder than normal. Overall, demand for the fall was 3.9 percent lower than the previous fall. After adjusting for weather, the decline in fall demand was somewhat moderated, decreasing by 1.3 percent over the fall of 2018. Distributor loads showed a decrease of 3.9 percent or 0.8 percent, after correcting for weather.

Wholesale customers' loads decreased by 5.0 percent compared to the previous fall, carrying the slight declines from the tail of the summer into the fall. Five consecutive months of declines raise caution flags and bear further monitoring. Of the Big Six sectors, only chemicals (10.7%) showed year-over-year growth in the fall. The remaining sectors – mining (-1.2%), pulp and paper (-10.5%), refining (-20.6%), iron and steel (-3.5%) and vehicle manufacturing (-6.8%) saw some large declines, in part, due to a particularly strong fall of 2018. However, the numbers are still lower than the fall of 2017.

Figure 3.7 shows weather-corrected distributor load and embedded generation output. Though embedded generation shows seasonal volatility, the underlying upward trend is evident until 2016, when the output appears to level off. For the year to date, embedded generation is down 0.5 percent compared to last year. Year-to-date embedded generation output is 5.9 TWh.

For the six months from June to November, distributors' loads decreased by 3.9 percent compared to the same six-month period in 2018. Weather-corrected values were down 1.5 percent over 2018. Embedded generation increased by 5.5 percent over the same period a year ago.

Figure 3.7: Monthly Weather-Corrected Distributor Load and Embedded Generation Output

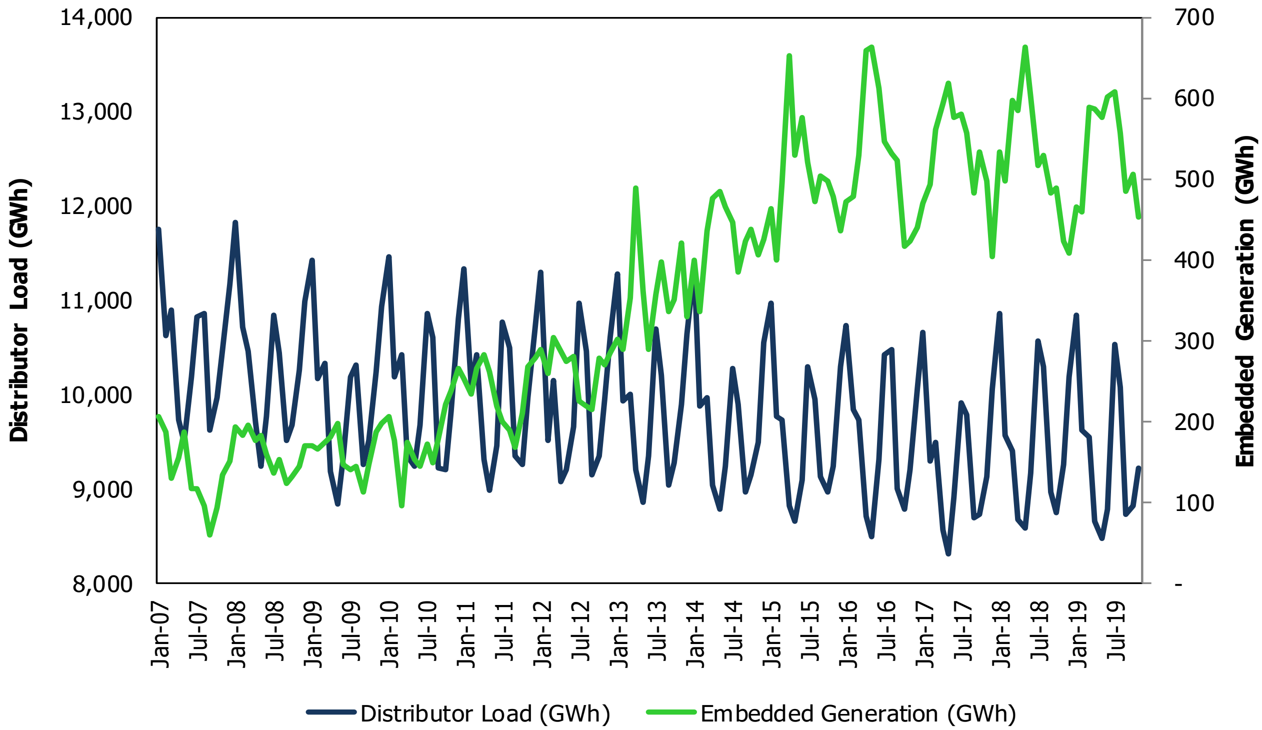


Figure 3.8 shows the year-over-year change in wholesale customers' average hourly consumption. The graph traces the impact of the recession and the relatively flat demand since that time. Economic restructuring after the 2009 recession is not unique to Ontario. The combination of technology, a shift to service sector industries and the rise of manufacturing in developing countries has led to flat or declining manufacturing in advanced economies.

Figure 3.9 shows the wholesale customers' highest monthly average hourly load by industry segment for each of 2008 and 2019 year to date. The purpose of this graph is to illustrate how demand has changed across various electricity-intense sectors of the economy. Only the mining sector and refining are above their pre-recession levels. All other major sectors saw a significant decline in 2009 and relative stability since. Some of the change is due to the economic cycle, while others are sector specific. The decline in demand for newsprint explains the decline in the pulp and paper sector.

Figure 3.8: Wholesale Customers' Year-over-Year Change in Consumption

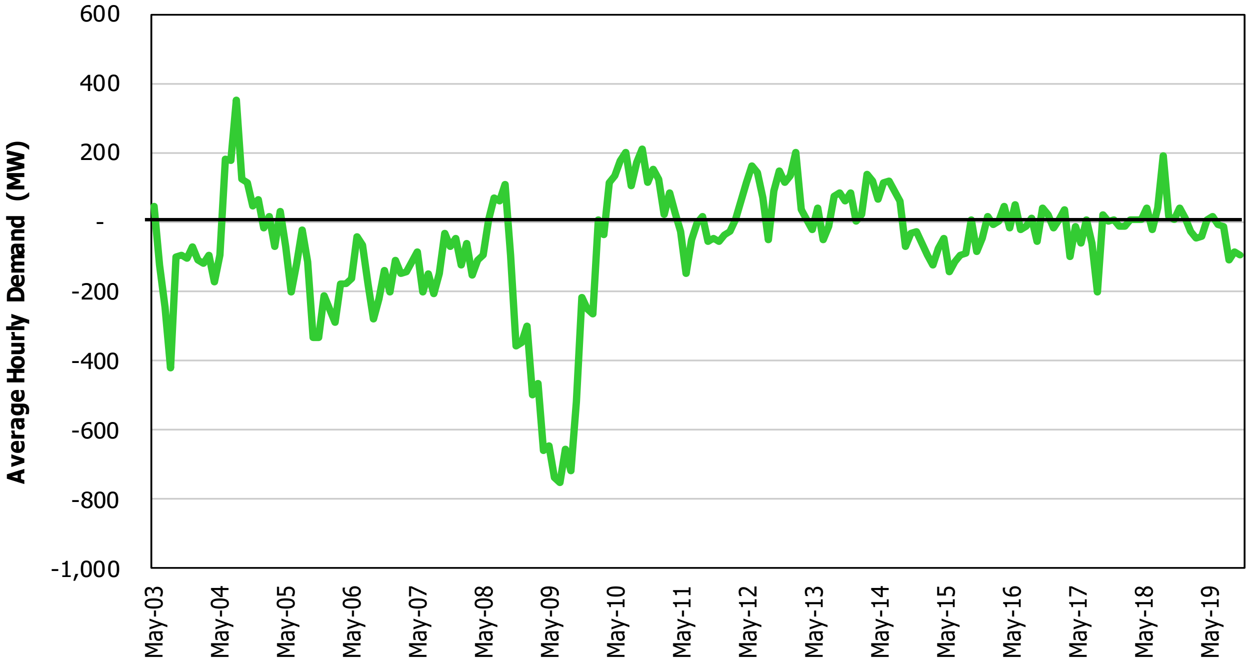


Figure 3.9: Wholesale Customers' Average Hourly Consumption by Industry Segment

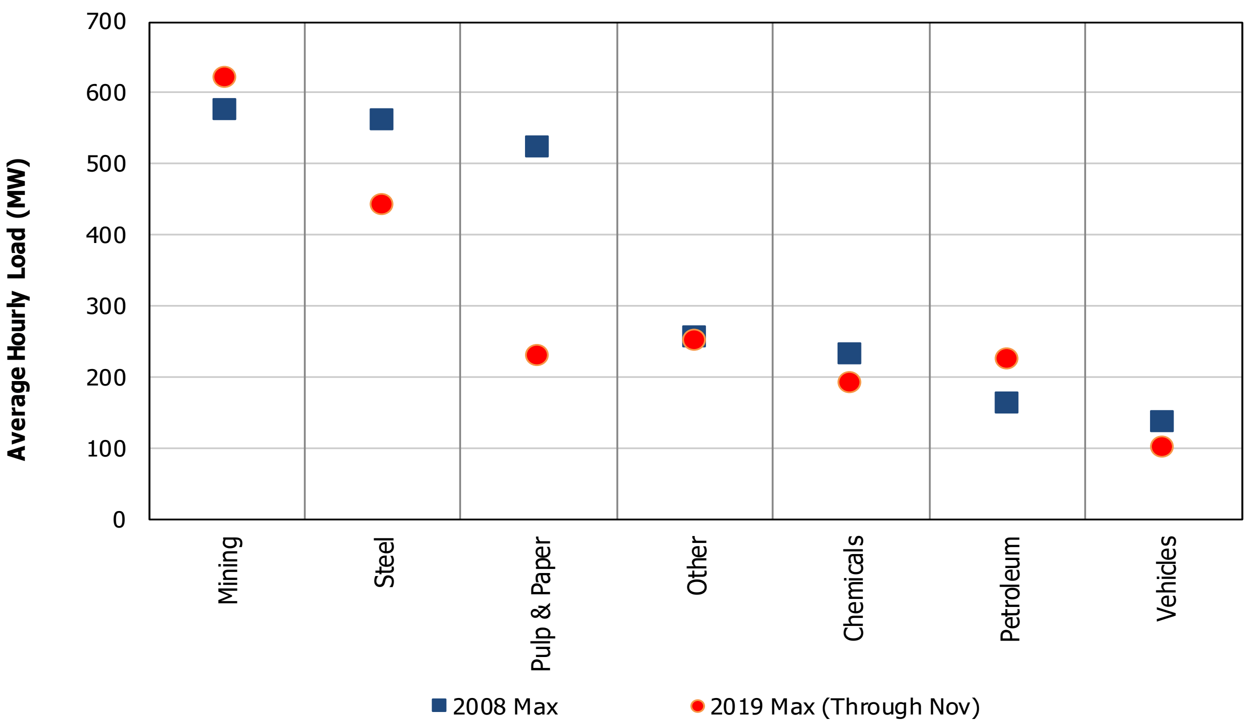


Table 3-2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week and notes any item of significance for the week. If the weather-corrected demand is greater than the actual demand, actual weather was milder than normal. Additional history is available in the Reliability Outlook Tables spreadsheet in Table 3-3.1.

Table 3-2: Historical Weekly Energy Demand

Week Number	Week Ending	Peak Day	Actual Energy (GWh)	Corrected Energy (GWh)	Notes
23	09-Jun-19	07-Jun-19	2,317	2,325	
24	16-Jun-19	10-Jun-19	2,308	2,311	
25	23-Jun-19	19-Jun-19	2,597	2,603	
26	01-Jul-18	29-Jun-18	2,799	2,753	
27	08-Jul-18	05-Jul-18	2,904	2,816	Canada Day
28	15-Jul-18	15-Jul-18	2,951	2,875	
29	22-Jul-18	16-Jul-18	2,796	2,716	
30	29-Jul-18	24-Jul-18	2,794	2,699	
31	05-Aug-18	05-Aug-18	2,896	2,782	
32	12-Aug-18	09-Aug-18	2,880	2,727	Civic Holiday
33	19-Aug-18	14-Aug-18	2,942	2,772	
34	26-Aug-18	20-Aug-18	2,693	2,552	
35	02-Sep-18	28-Aug-18	2,861	2,740	
36	09-Sep-18	05-Sep-18	2,757	2,550	Labour Day
37	16-Sep-18	14-Sep-18	2,678	2,560	
38	23-Sep-18	17-Sep-18	2,567	2,453	
39	30-Sep-18	25-Sep-18	2,366	2,378	
40	07-Oct-18	02-Oct-18	2,378	2,377	
41	14-Oct-18	10-Oct-18	2,374	2,313	Thanksgiving Day
42	21-Oct-18	17-Oct-18	2,381	2,263	
43	28-Oct-18	24-Oct-18	2,500	2,438	
44	04-Nov-18	29-Oct-18	2,491	2,479	
45	11-Nov-18	09-Nov-18	2,543	2,517	Remembrance Day
46	18-Nov-18	14-Nov-18	2,694	2,560	
47	25-Nov-18	22-Nov-18	2,729	2,716	

3.3 Historical Peak Demand

Peak demands are weather-driven and generally occur on weekdays. Peak demands have been facing downward pressure due to a number of factors. Conservation, time-of-use rates, embedded generation, demand response, the Industrial Conservation Initiative (ICI) and economic restructuring have all contributed to lower peak demands.

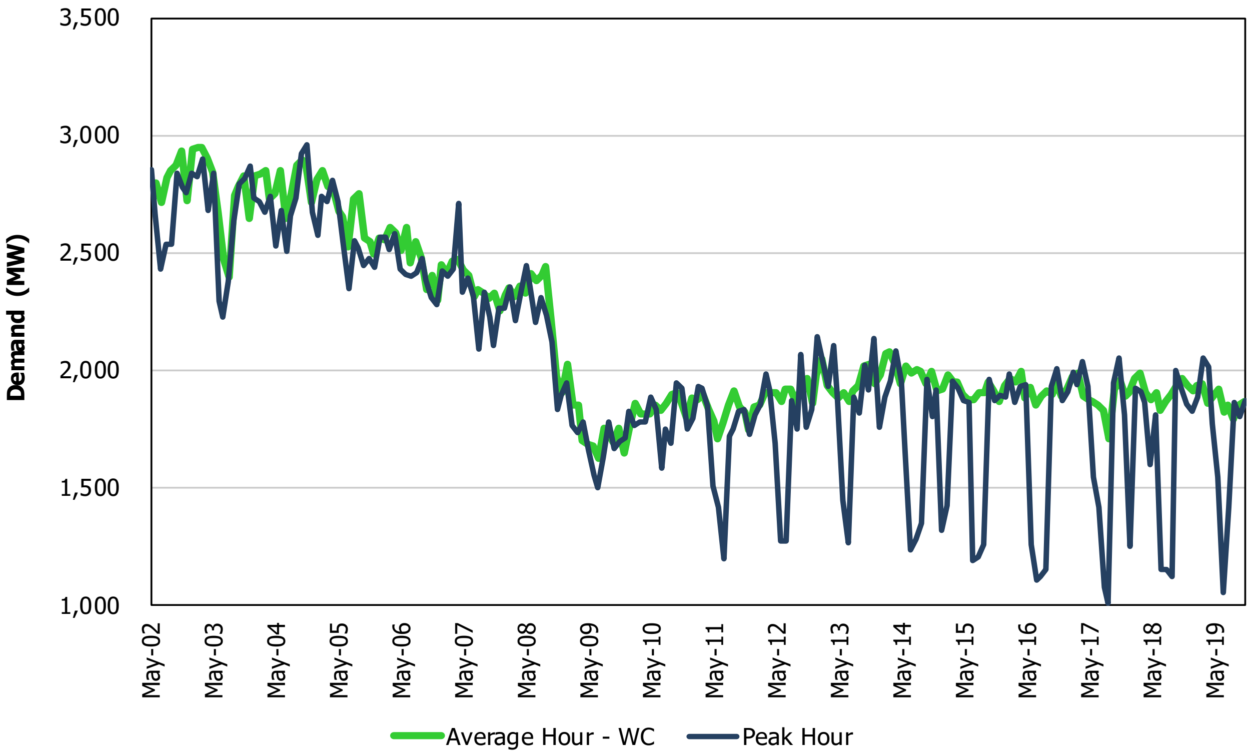
The summer peak was 21,791 MW, similar to peaks in 2014 and 2017, when summers were cool. ICI activity occurred on the peak summer days, reducing demand well in excess of 1,200 MW.

The fall peak was 19,717 MW, the lowest since 2009, which occurred during the financial market meltdown. This fall peak occurred during mid-September (28.6 °C). October had a warm weather peak (31.2 °C), which was not common until recently. The last three Octobers had warm weather peaks early in the month. November's peak was driven by cold weather.

Figure 3.10 shows the wholesale customers' average hourly monthly demand and their consumption at the time of the system peak. Prior to the ICI program, the average and coincident peaks tracked quite closely as many sectors operated 24/7. With the introduction of the ICI program in 2010, wholesale customers have responded by reducing their load during the five peak days. The graph shows a portion of the response as the program applies to Class A customers, which include wholesale customers and a number of customers served by distributors.

In 2017, the program was expanded to include customers with a peak load of 0.5 MW or higher. Additionally, for those with an average peak load in excess of 1 MW, the North American Industrial Classification (NAIC) code restrictions were lifted. Previously, participants were restricted to manufacturing sectors. Those between 0.5 MW and 1 MW are still restricted to specific sectors: manufacturing, greenhouses and floriculture. The elimination of the NAIC classification enabled large commercial facilities to access the program. This also made it more difficult to assess the impact of the ICI program. Commercial facilities are generally weather-sensitive loads and that complicates the estimation process but, more important, these new participants are almost exclusively served by distributors and the IESO does not have access to the hourly consumption required to calculate ICI savings.

Figure 3.10: Wholesale Customers' Coincident Peak and Average Hourly Consumption



For most years, the province has been summer peaking, but the summer peaks have been facing more downward pressure than the winter peaks. In particular, conservation and embedded solar generation did not impact seasonal peaks to the same degree. The summer peak is primarily driven by air conditioning load, whereas the winter peak results from a mix of end uses. As such, conservation programs that increase air conditioner efficiency and improve the building envelope will have a direct impact on summer peak. The winter peak is mostly impacted through conservation initiatives that improve lighting efficiency, and the resulting impact on the winter peak is smaller. The second factor is embedded solar generation. Since the winter peak occurs after sunset, the output of embedded solar has been near to zero and has no impact on the winter peak. The summer peak had occurred during daylight hours when embedded solar output is significant. This both reduces the summer peaks and pushes them to later in the day.

Traditionally, the summer peak occurred in the late afternoon as air conditioners worked to dissipate the accumulated heat. Now embedded solar has effectively "carved out" demand in the middle of the day and pushed the peak to later in the day when solar output is declining more rapidly than demand.

Figure 3.11 shows the summer weekday peaks levels in MW and the hour in which they occurred for the summers of 2004, 2014 and 2019. The graph clearly shows that peaks are lower today – a result of conservation and lower industrial load – but are also occurring later in the day as a result of the offsets of embedded solar generation.

Figure 3.12 shows the weekday peaks in MW and the hour in which they occurred for the fall of 2004, 2014 and 2019. The fall peaks are mixed, being driven by both heating load in October and November and cooling load in September. The time change also has an impact on the timing of the peaks. The heating load peaks occur later in the day and those have been pushed later in the day and lower. The cooling load peaks occur in the middle of the day and those have been reduced and pushed outside of the solar output time frame.

Figure 3.11: Seasonal Weekday Peak Hour Distribution – Summer

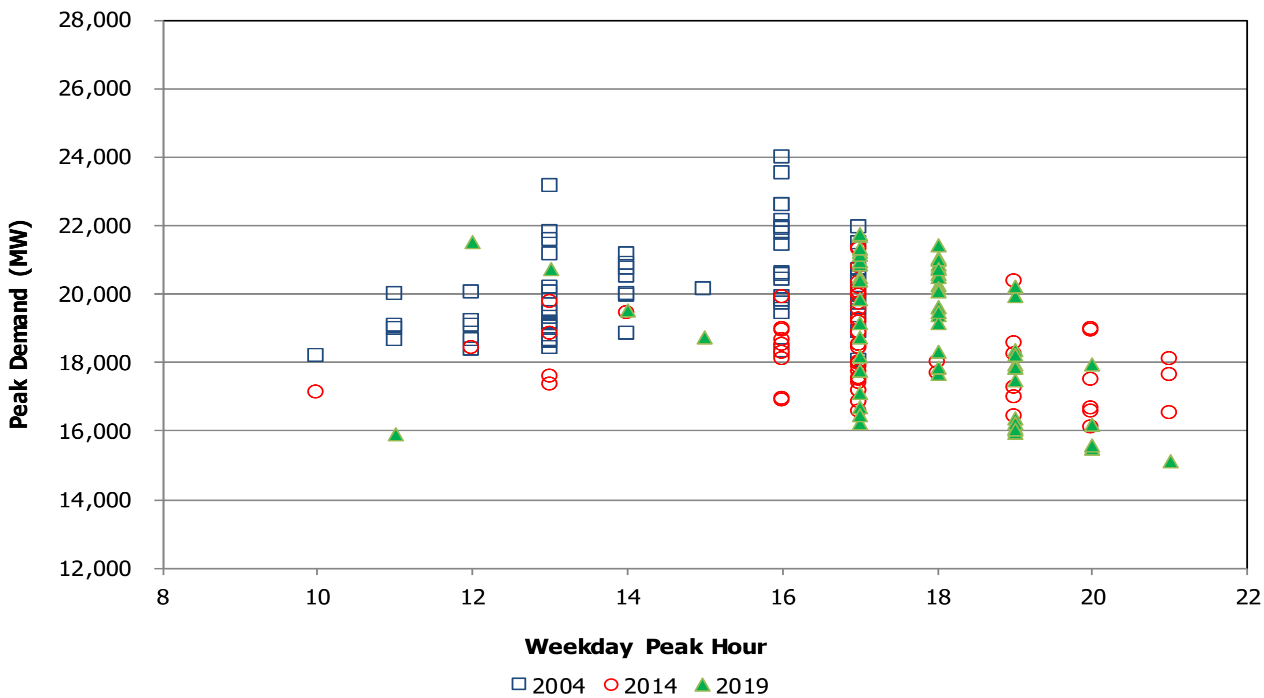


Figure 3.12: Seasonal Weekday Peak Hour Distribution – Fall

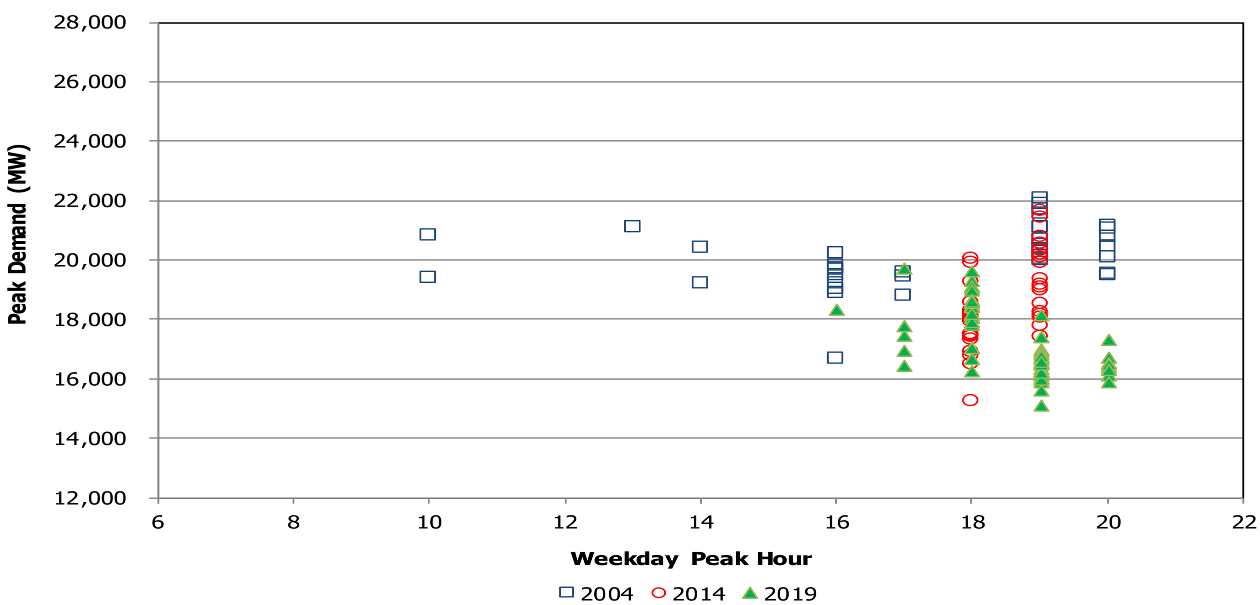


Figure 3.13 shows the breakdown for the past four seasonal peaks. The graph illustrates the factors that impact the peak. The winter and spring peaks occurred later in the day when embedded solar output was quite small and embedded output was being driven by wind generation. The latter two peaks – summer and fall – had more significant embedded generation output as solar was still active at the time of the peaks. ICI only impacted the summer peak and the winter peak. Minimal demand response was activated across the peaks – 7 MW for the fall peak.

Figure 3.13: Anatomy of Seasonal Peaks

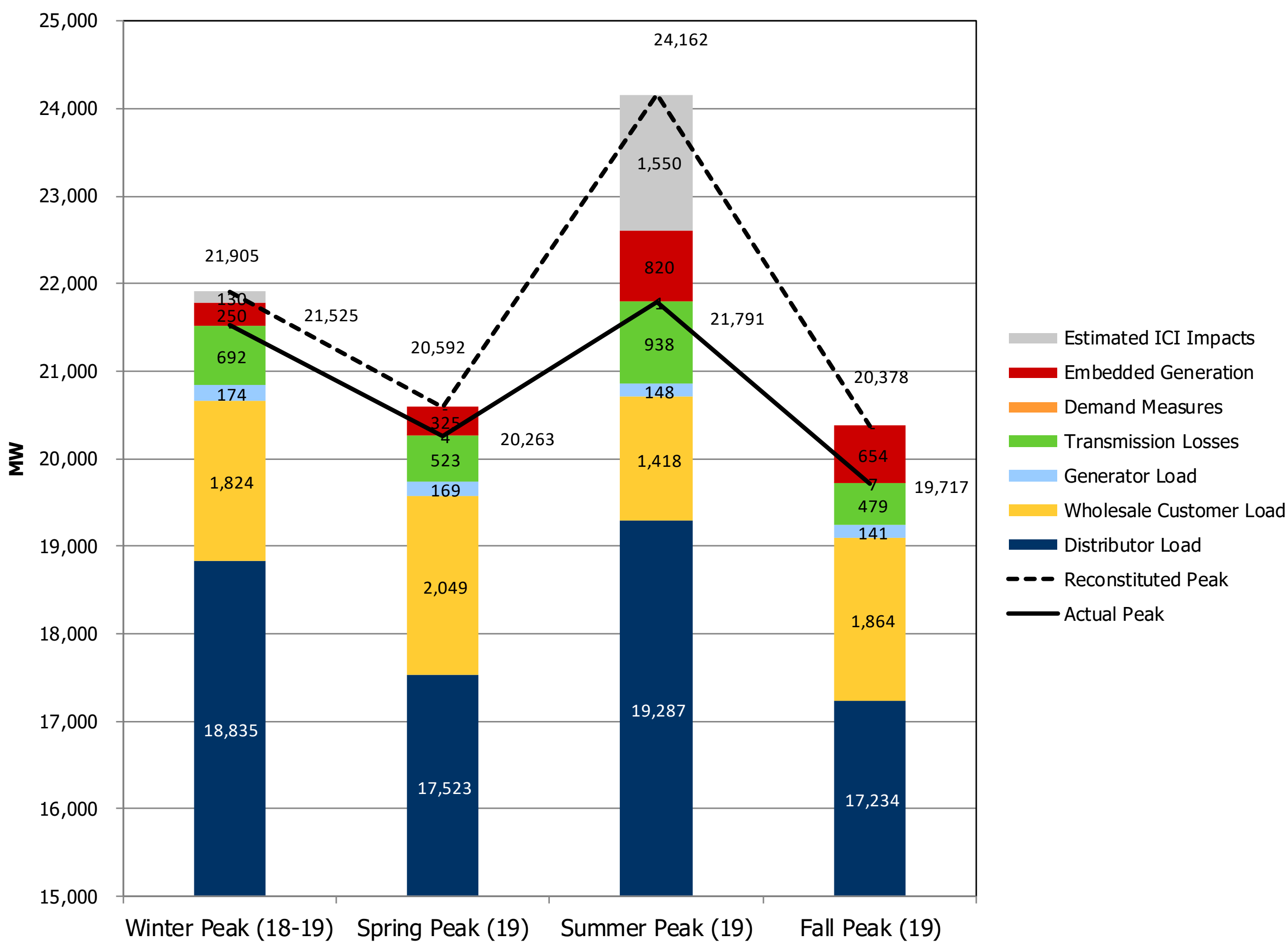


Table 3-3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3-3: Historic Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
23	09-Jun-19	07-Jun-19	16,369	16,448	25.8
24	16-Jun-19	10-Jun-19	16,253	16,212	18.4
25	23-Jun-19	19-Jun-19	17,896	18,323	24.8
26	30-Jun-19	27-Jun-19	20,248	21,043	28.9
27	07-Jul-19	05-Jul-19	21,716	21,064	30.2
28	14-Jul-19	10-Jul-19	21,083	19,695	28.9
29	21-Jul-19	20-Jul-19	21,645	21,069	32.4
30	28-Jul-19	28-Jul-19	21,027	20,451	30.5
31	04-Aug-19	29-Jul-19	21,791	21,031	31.4
32	11-Aug-19	07-Aug-19	21,033	21,585	27.7
33	18-Aug-19	13-Aug-19	21,000	21,029	28.1
34	25-Aug-19	21-Aug-19	21,354	22,100	30.2
35	01-Sep-19	28-Aug-19	18,748	18,636	26.9
36	08-Sep-19	03-Sep-19	17,642	17,589	22.0
37	15-Sep-19	11-Sep-19	19,717	19,244	28.6
38	22-Sep-19	22-Sep-19	18,803	18,337	30.7
39	29-Sep-19	23-Sep-19	17,806	17,643	24.3
40	06-Oct-19	01-Oct-19	18,329	18,853	31.2
41	13-Oct-19	07-Oct-19	16,354	16,519	17.7
42	20-Oct-19	17-Oct-19	16,784	17,289	8.5
43	27-Oct-19	24-Oct-19	16,518	16,590	13.4
44	03-Nov-19	01-Nov-19	17,041	17,065	4.6
45	10-Nov-19	07-Nov-19	18,156	17,903	2.4
46	17-Nov-19	13-Nov-19	19,625	19,001	-4.1
47	24-Nov-19	18-Nov-19	18,982	18,605	2.1

3.4 Load Duration Curves

The following load duration curves display load for the four seasonsfall (September, October and November) summer (June, July and August), spring (March, April and May) and winter (December, January and February).

The figures are not weather-corrected, so the weather will influence the shape of each of the graphs. The spring and fall load duration curves are more heavily influenced by the level of economic activity than by the weather. Those load duration curves show that demand for 2019 was low by historical standards.

Figure 3.14: Fall Load Duration Curve

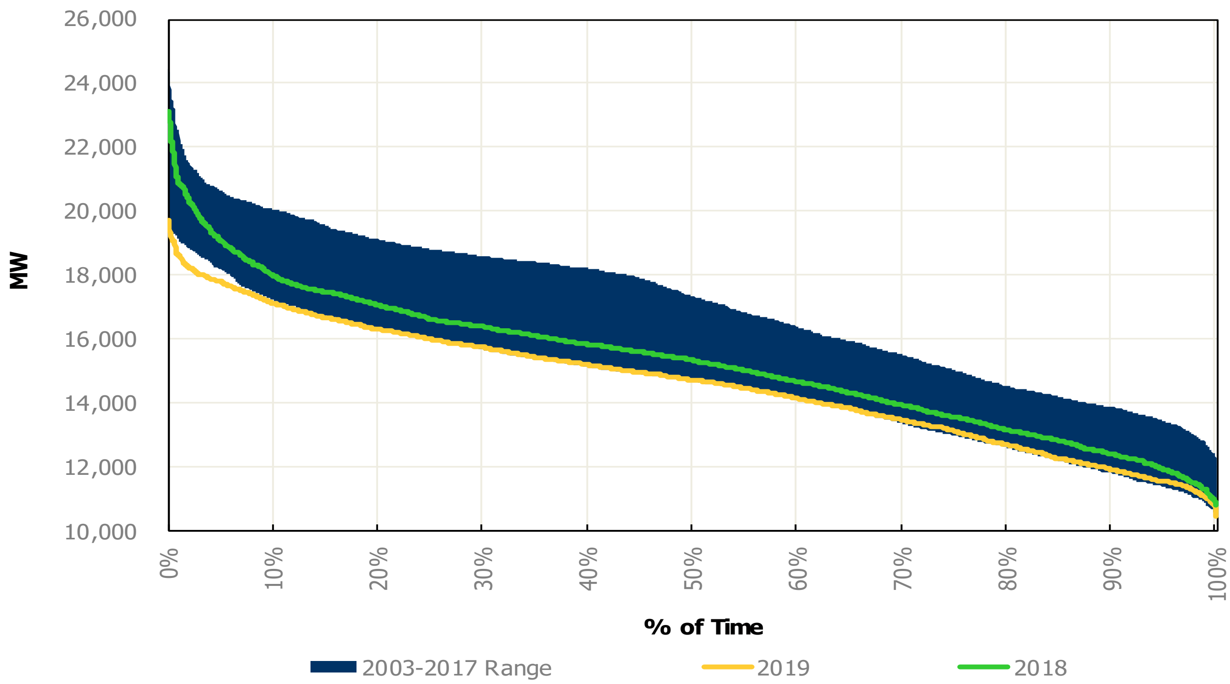


Figure 3.15: Summer Load Duration Curve

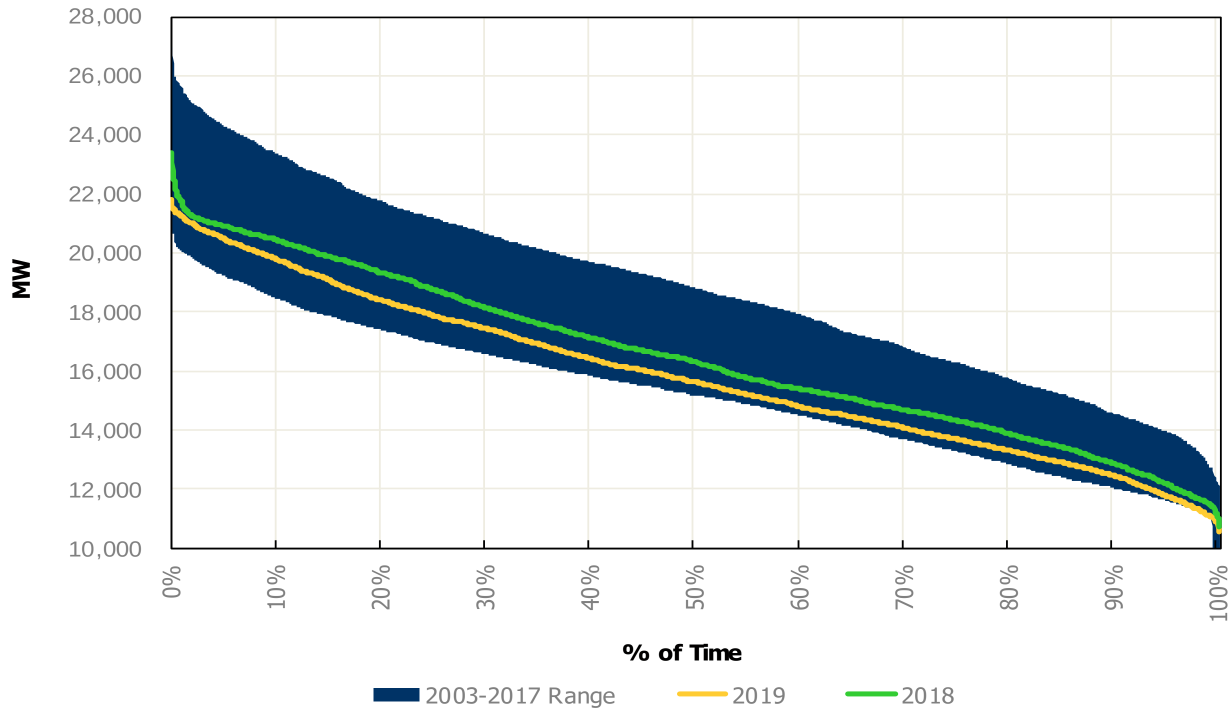


Figure 3.16: Spring Load Duration Curve

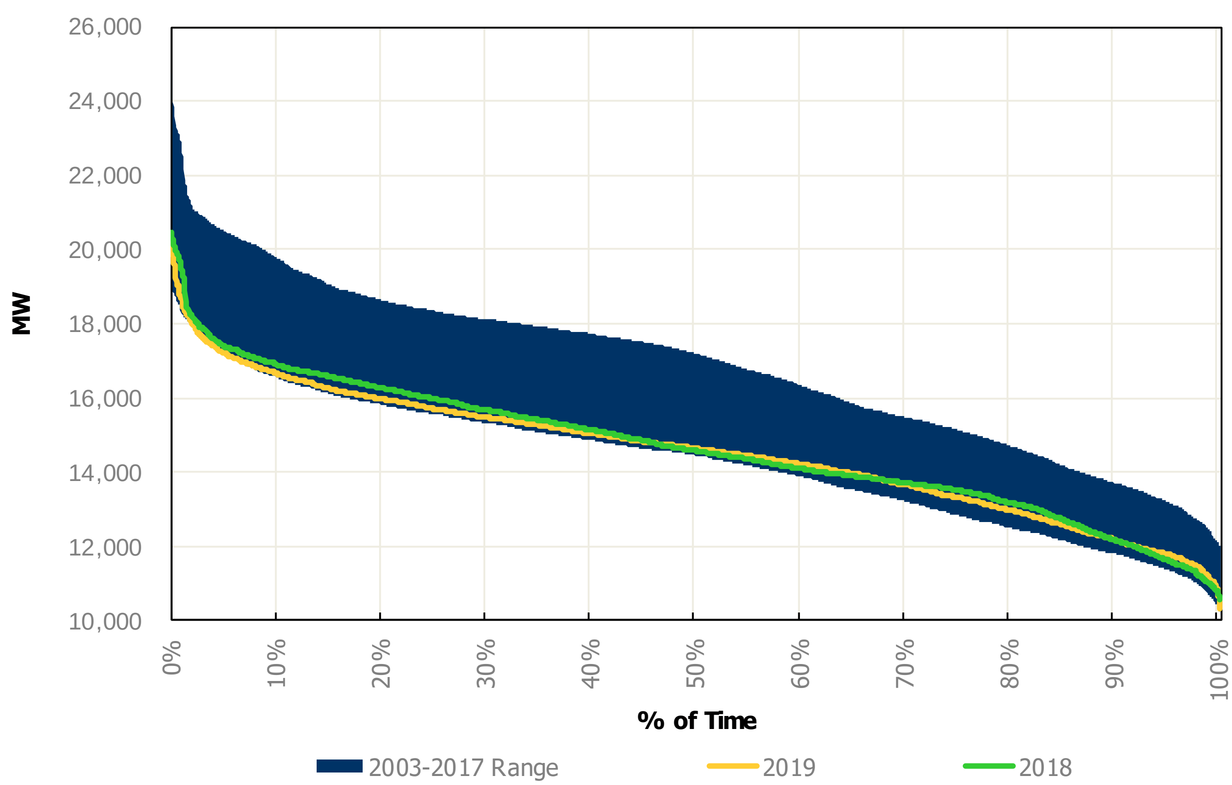
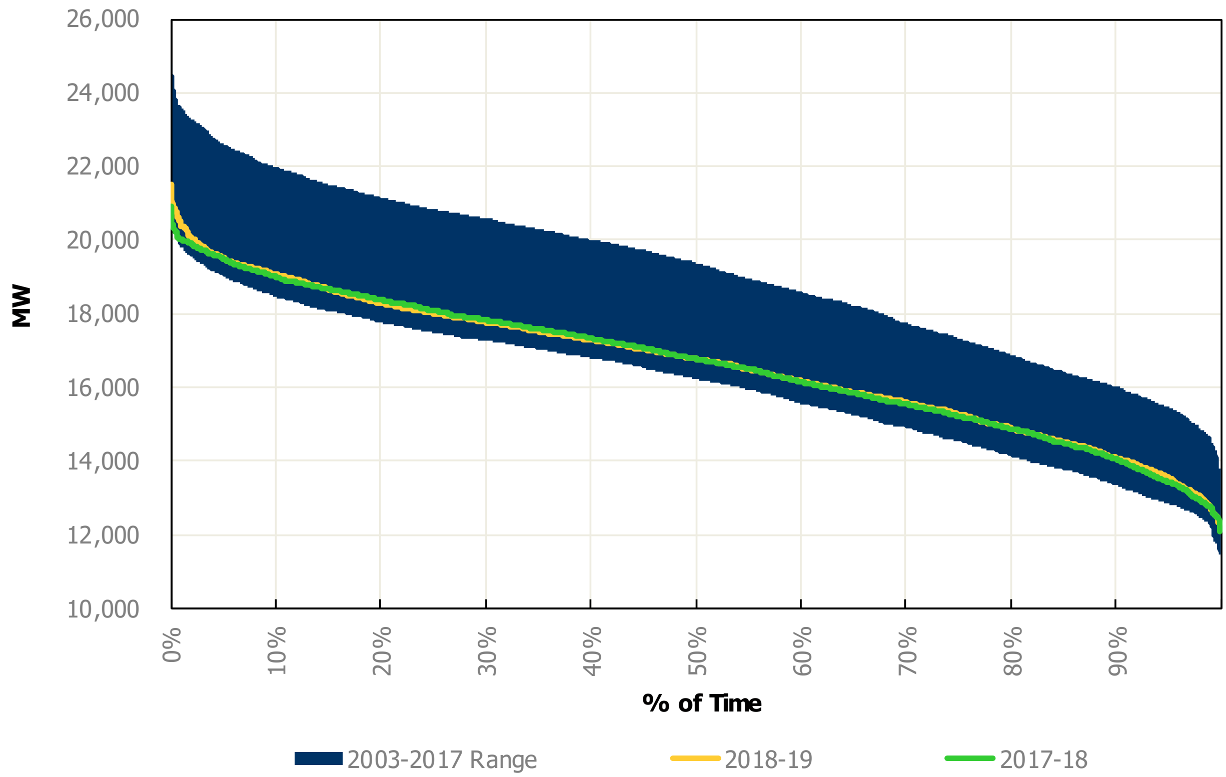


Figure 3.17: Winter Load Duration Curve



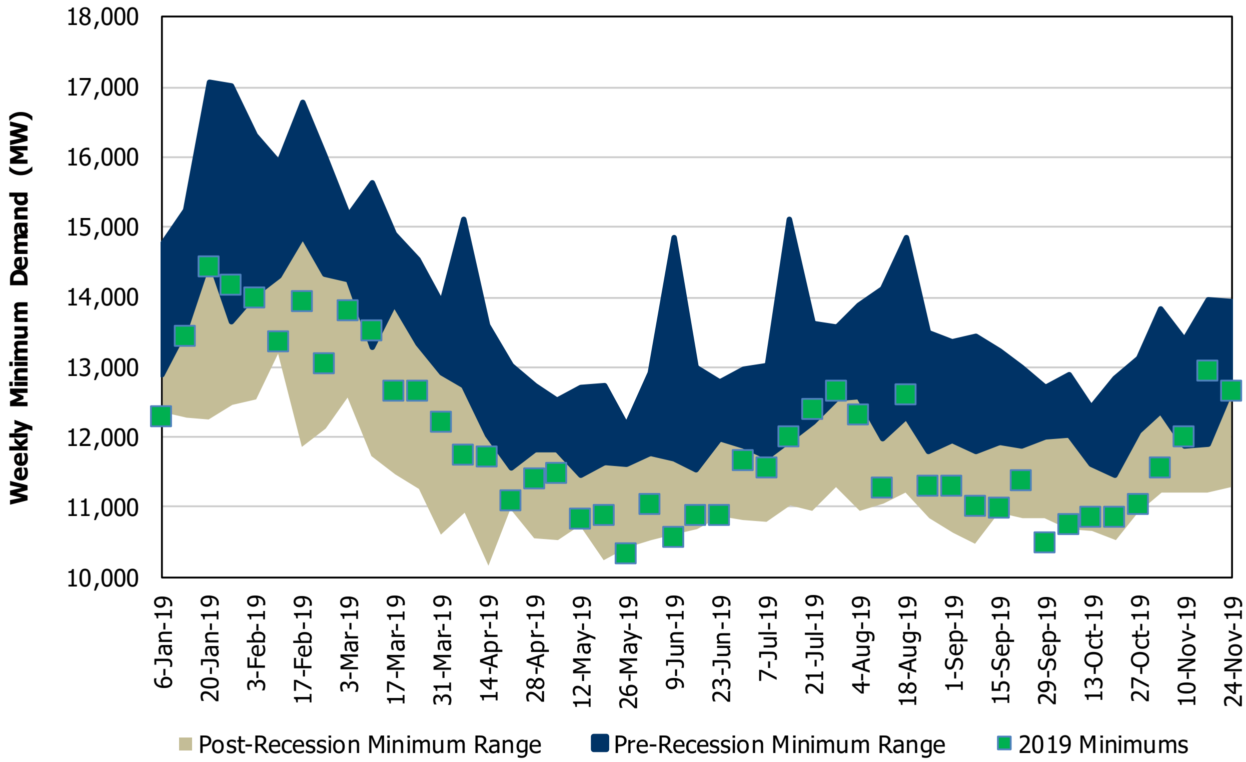
3.5 Historical Minimum Demand

Similar to peak demands, minimum demands are driven by weather, calendar and economic effects. The importance of the drivers varies by season. Winter, spring and fall have the potential for heating load, whereas the summer period has the potential for cooling loads. Minimums have continued to establish new lows in the post-recession era due to lower industrial loads, conservation and increased embedded generation. When minimums occur during the predawn hours, embedded wind is further reducing the need for grid-supplied electricity. In fact, some load points with high quantities of embedded wind actually push power back onto the grid overnight when embedded wind output is high.

Figure 3.18 shows the minimum weekly demands for the period January to November since market opening. The dark band represents the range of values for the years 2002 – 2008, while the lighter band shows the post-recession minimums for the 2009 - 2018 time frame. The squares represent the weekly minimums for the past 11 months.

The minimums over the winter period are fairly high reflecting the cold weather. However, as the heating load dissipated over the spring, minimums fell to new historic lows, reflecting the decline in baseload demand. That pattern was repeated in the fall when mild September and October weather reduced the need for space heating or cooling and minimums established new lows. The cold weather in November drove the minimums higher. The weekly minimums occur during the early morning hours of the weekend, when the level of economic activity is lowest.

Figure 3.18: Weekly Minimum Demands



- End of Section -

4. Forecasting Process and Assumptions

A detailed description of the forecasting methodology can be found in the document entitled "Methodology to Perform Long-Term Assessments" found on the IESO website at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2019dec.pdf.

The most recent demand, weather and economic data were incorporated into the model, which was re-estimated based on this information. The forecast of demand requires inputs, and this section covers each class of drivers.

4.1 Calendar Drivers for Forecast

Calendar variables are addressed in the Methodology document. Essentially, forecasting demand for electricity according to the calendar – days of the week, holidays, sunrises and sunsets – is straightforward.

4.2 Economic Drivers for Forecast

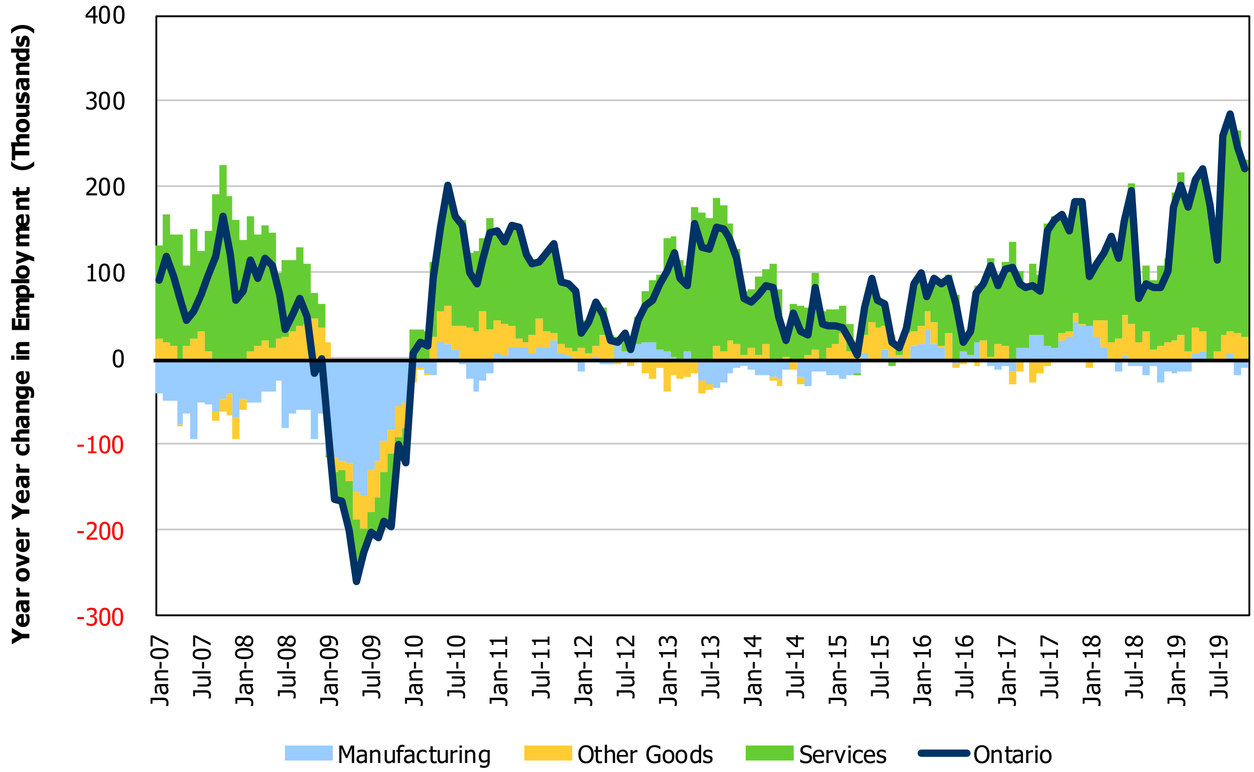
To produce an energy and peak demand forecast, an economic forecast of various drivers is required. The IESO uses both a consensus of publicly available provincial forecasts and purchases forecasts of economic data in order to generate economic drivers for the demand forecast and to provide additional insight and analysis.

The economic fundamentals – low interest rates, a lower dollar, high consumer confidence and strong U.S. growth – all create an environment that benefits both Canada and Ontario over the forecast horizon. As well, one of the most significant risks noted in previous outlooks appears on the path to resolution. The amended CUSMA was signed by leaders of the three nations and now awaits ratification. Recent news also indicates that a trade deal is likely between the U.S. and China, further reducing the negative trade disruption impacts. There's still a significant downside risk as personal and public debt levels are exposed to potential interest rate hikes. Consumer spending is currently lagging employment growth due to debt levels and any rate increase would increase carrying costs and reduce spending further.

Ontario economic growth was strong throughout 2019 and employment growth is expected to be the highest since 2003. Looking forward, Ontario's economy is expected to continue to grow over the 2020-21 time frame. However, projections are calling for much lower employment growth of roughly 1.0 to 1.2 percent, more reminiscent of that in the period 2014-16.

Figure 4.1 shows the year-over-year changes in employment broken down into services, manufacturing and other goods (e.g., mining, construction, agriculture and forestry). A broad-based and sustainable growth pattern would have growth across all of the sub-sectors. The graph illustrates the strong rebound in total employment throughout 2019. For the year to date through November, overall Ontario employment is up 2.9 percent over the same period in 2018. Manufacturing jobs – which are most strongly tied to electricity demand – have not been part of that overall growth. For 2019, manufacturing jobs have declined 0.7 percent compared to 2018, while the service sector and construction have both experienced strong growth of 3.3 percent and 3.2 percent respectively. These sectors are less tied to electricity demand.

Figure 4.1: Composition of Ontario's Employment Growth



Where employment growth is occurring is also indicative of the health of the economy. Once again, geographically broad-based growth is desirable for a robust economy. At times, employment growth or job losses have been concentrated within the GTA or in another region in the province. Throughout 2019, job growth has been fairly balanced across the province. Granted there are some regional differences, as both the Northwest and Windsor area have shed jobs throughout 2019, but the growth is balanced enough not to raise concerns about whether the data is masking negative developments. Figure 4.2 shows the year-over-year employment change for Toronto and the rest of the province.

Figure 4.2: Zonal Employment Growth

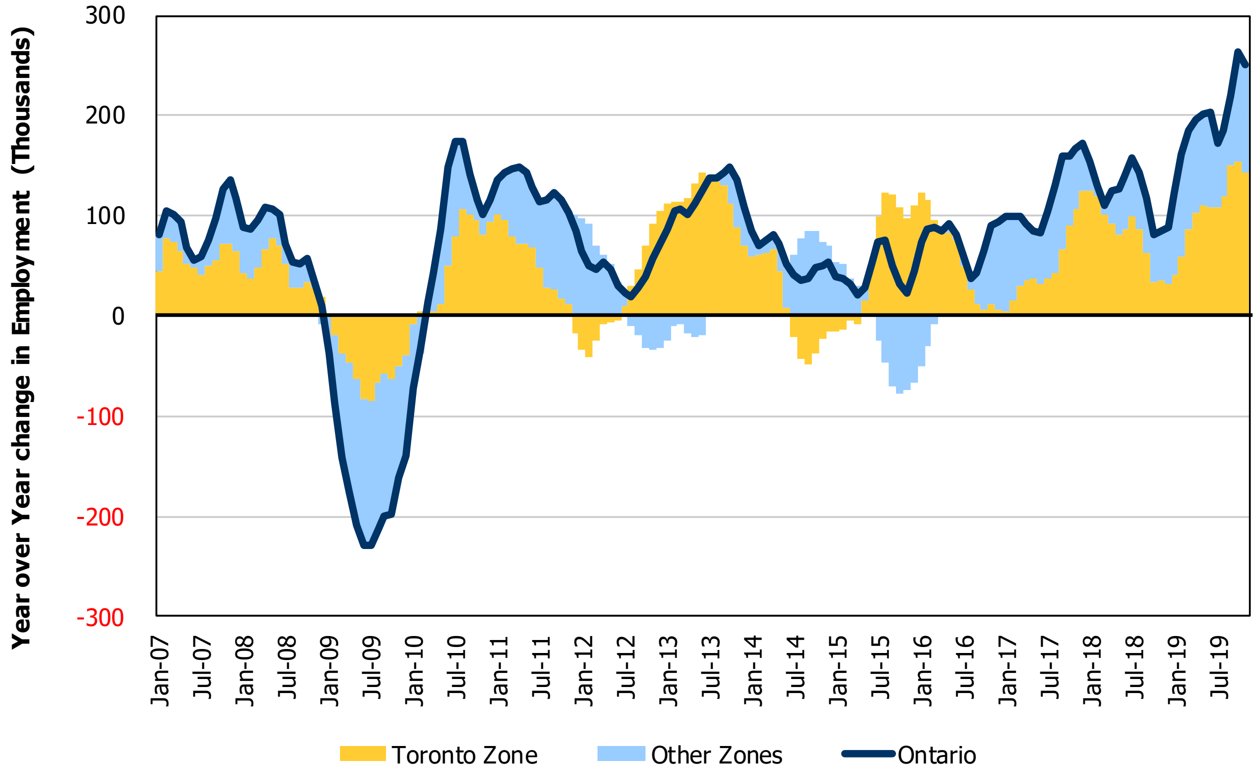


Table 4-1 summarizes the key economic drivers for the demand forecast. The Ontario growth index is a weighting of the economic drivers as they relate to demand.

Table 4-1: Forecast of Ontario Economic Drivers

Year	Ontario Employment		Ontario Housing Starts		Ontario Growth Index	
	Thousands	Annual Growth (%)	Thousands	Annual Growth (%)	Index	Annual Growth (%)
2001	5,921	2.1	70.3	4.2	1.150	1.88
2002	6,034	1.5	79.6	13.3	1.169	1.65
2003	6,213	3.1	80.9	1.7	1.198	2.49
2004	6,314	1.7	79.9	-1.3	1.219	1.81
2005	6,381	1.3	73.2	-8.4	1.236	1.39
2006	6,452	1.5	67.8	-7.4	1.253	1.35
2007	6,545	1.6	62.8	-7.4	1.271	1.41
2008	6,610	1.5	71.9	14.6	1.287	1.23
2009	6,433	-2.7	47.9	-33.3	1.276	-0.85
2010	6,538	1.6	57.1	19.1	1.294	1.41
2011	6,658	1.8	65.2	14.3	1.314	1.6
2012	6,703	0.7	74.4	14.1	1.329	1.09
2013	6,823	1.8	58.6	-21.2	1.348	1.49
2014	6,878	0.8	56.2	-4.2	1.361	0.96
2015	6,923	0.7	68.3	21.6	1.375	1.00

2016	7,000	1.1	71.9	5.2	1.392	1.25
2017	7,128	1.8	75.2	4.7	1.415	1.64
2018	7,242	1.6	76.0	1.0	1.436	1.52
2019 (f)	7,435	2.7	67.4	-11.3	1.464	1.95
2020 (f)	7,522	1.2	69.1	2.5	1.482	1.22
2021 (f)	7,599	1.0	70.0	1.4	1.499	1.15

4.3 Weather Drivers for Forecast

Since forecasting long-term weather is not possible, weather scenarios are generated using historical data. The analytical studies that the IESO produces serve a variety of purposes and needs. As such, the IESO produces demand forecasts based on a number of different weather scenarios, the most common being "normal" and "extreme."

The weather scenarios are generated using the following steps:

For each day over the past 31 years, a "weather factor" is calculated based on the weather conditions of that day (temperature, wind speed, cloud cover and humidity). This weather factor represents the MW impact on demand if those weather conditions were observed in the forecast horizon.

The daily weather factors are sorted from highest to lowest for each month.

Normal weather is based on the median value of the sorted weather factors across the 31 years of history. For example, the median value of the maximum weather factor each January from 1980 to 2010 would be the first value for the normal January. The median value of the second highest weather factor each January from 1980 to 2010 would be the second day in the normal January. This is repeated until all days in the month are generated. Once the normal months are created, they are mapped to the calendar based on the weekly average distribution of weather. The weekly peak-eliciting weather is always mapped to Wednesday to ensure that peaks do not occur on weekends or holidays.

Extreme weather is generated in a similar manner except that the maximum, rather than the median, value from the sorted 31-year history is used.

Load forecast uncertainty (LFU) – a measure of demand fluctuations due to weather variability – is a critical part of the analysis. In conjunction with the normal weather forecast, LFU is valuable in determining a distribution of potential outcomes under various weather conditions. The resource adequacy assessments use the normal weather forecast in combination with LFU to consider the range of peak demands that can occur under various weather conditions with varying probability

The extreme weather scenario is valuable for studying situations where the system is under duress. Although useful when examining peak conditions, it is unrealistic from an energy demand standpoint, as severe weather conditions do not persist over a long time period.

The Outlook Tables spreadsheet includes Table 3-3.5, which has the normal and extreme weather scenarios. For each week, the table shows the historical weather used for the peak day of that week. The table shows the daily high (temperature) and wind speed. Not shown but used in forecasting demand are humidity and cloud cover. The IESO uses six weather stations in the demand models – the data in the table is for Toronto.

4.4 Demand Measures and Load Modifiers

A number of initiatives and policies have an impact on electricity demand. These can be grouped into two categories: demand measures, which are not incorporated into the demand forecast, and load modifiers, which are included. In essence, demand measures are controllable while load modifiers are not. Demand measures include dispatchable loads and the capacity from the demand-response auction. Load modifiers include conservation, prices and embedded generation.

Demand Measures

Demand measures are dispatched like a generation resource. Whether you dispatch a gas plant to meet a level of demand or dispatch a load off to reduce that level of demand, the system is indifferent, as supply effectively equals demand. For correct accounting, demand measures must be treated equitably on both sides of the ledger. Since demand measures are included in the supply mix to be dispatched off, demand must be forecasted at the higher level prior to demand measures. The historical demand is reconstituted to include load that was shed through various demand-response programs. Demand measures have no impact on the demand forecast.

Load Modifiers – Conservation

Conservation includes provincial energy-efficiency programs, codes and standards and fuel switching. Projected conservation numbers are based on committed provincial programs.

The impacts of conservation vary according to the program mix. For example, programs that promote increasing the efficiency of air conditioners will reduce the demand for electricity in summer but have no impact in the winter. Programs aimed at improving the insulation of building envelopes will impact electricity consumption year round.

Projected conservation impacts are incorporated into the demand forecast reducing forecasted demand.

Load Modifiers – Prices

Prices include the impact of time-of-use (TOU) rates and the Industrial Conservation Initiative (ICI). Both are factored into the demand forecast and assessed as information is gathered and analyzed. The impact of these programs continues to evolve as market participants and consumers gain more experience and adjust their consumption.

TOU impacts will vary as rates are set; the greater the price ratio between off and peak prices, the greater the likelihood that consumers will react to prices. The overall impact will be to shift load within the day or week to off-peak hours and/or the weekend. Overall, peaks will be impacted more than energy in the short term. However, an increased awareness of electricity pricing will lead consumers to make equipment and usage decisions that can impact total electricity consumption in the future.

The ICI offers a financial incentive to participants who reduce their consumption at the time of the peak for the five highest peak days. The program runs from May to April. The ICI was expanded this year to allow customers in the manufacturing and greenhouse sectors with an average monthly peak demand greater than 500 kW and less than 1 MW to participate. As well, sector restrictions were lifted for customers with a peak greater than 1 MW. This will allow large commercial customers, such as hospitals, universities and hotels to participate. Peak reductions have grown both as the number of participants has increased and as participants have improved their ability to identify and react to peaks. First-year (2010) reductions were estimated at 200 MW, growing to an estimated ICI impact on the 2019 peak of 1,550 MW.

Both TOU and ICI impacts are incorporated into the demand forecast. Load-displacing generation, as opposed to distribution-connected generation (embedded), would also factor into the demand forecast as a load modifier.

Load Modifiers – Embedded Generation

Embedded generation refers to load-displacing generation that is located on the market participants' side of the meter. This would include all generation under the Renewable Energy Standard Offer Program (RESOP), all generation under the microFIT program and some generation under the Green Energy Act's Feed-in Tariff (FIT) program. It also includes distribution-connected generators that are not contracted through the above programs. Since all output provided by embedded generation is an offset to grid-supplied electricity, the impact of embedded generation is factored into the 18-month demand forecast as a reduction to demand.

For the forecast, embedded generation is split into groups according to fuel type: solar, wind, biomass, hydro and gas-fired generation. Figure 4.3 shows the installed and projected capacity of embedded generation by fuel type, with the vast majority being solar. Due to its large share, solar output is treated differently than that of other fuel types. The impact of solar generation is estimated using engineering models that use location, cloud cover and temperature to estimate solar production. The output of remaining embedded generation fuel types is produced using average production profiles based on history. The total embedded generation output is then incorporated into the demand forecast. Table 4-2 summarizes the estimated embedded capacity by fuel type as of December for the history and the forecast period. A more detailed table is included in the Reliability Outlook Tables.

Figure 4.3: Projected Embedded Generation Capacity

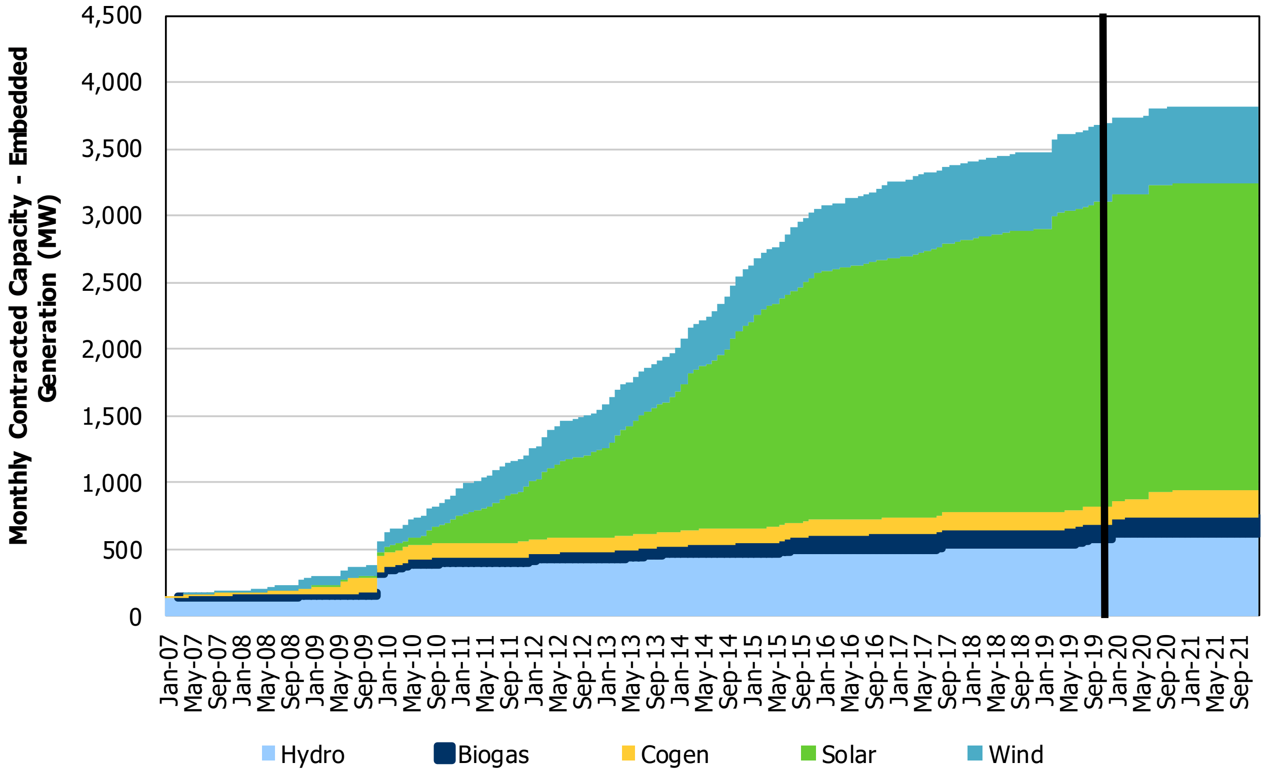


Table 4-2: Embedded Capacity

Month	Estimate of Contracted Embedded Generation Capacity (MW)					
	Biogas	**Cogen**	**Hydro**	**Solar**	**Wind**	**Total**
Dec-07	19	18	139	0	7	183
Dec-08	23	38	147	3	74	284
Dec-09	24	112	310	30	87	564
Dec-10	43	112	392	174	187	908
Dec-11	54	112	398	412	241	1,209
Dec-12	54	112	421	652	308	1,548
Dec-13	62	113	458	1,008	335	1,976
Dec-14	79	118	464	1,515	425	2,601
Dec-15	113	123	489	1,846	485	3,056
Dec-16	113	123	496	1,948	569	3,250
Dec-17	113	136	529	2,034	580	3,393
Dec-18	115	136	531	2,112	580	3,473

Dec-19	116	136	572	2,286	580	3,691
Dec-20	116	201	622	2,300	580	3,819
Dec-21	116	201	622	2,300	580	3,819

Over the course of the 18-month forecast, the amount of embedded installed capacity will increase by 85 MW raising the total to 3,819 MW. The amount of embedded generation capacity added over the forecast will be small compared to what the system has added the last several years.

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