Ontario Demand Forecast

JUNE 20, 2018

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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 July 2018 to December 2019 and supersedes the previous forecast released in March 2018.

Economic Outlook

Despite robust economic growth in 2017, electricity demand did not show the same growth in Ontario. This is attributable to a number of factors, but from an economic perspective it highlights the fact that the energy intensive sectors of the economy are generally not those sectors experiencing the greatest growth. Ontario's economy continues to undergo structural change as the service sector grows in relation to the goods sector.

The economic fundamentals remain very positive for the province and should help foster modest growth from the manufacturing sector. A low dollar, strong U.S. economy and low interest rates should help Ontario's energy intensive exporters. However, there remains considerable downside risk with the on-going NAFTA renegotiation and threat of tariffs on Canadian steel and aluminum producers. Tariffs on steel would impact Ontario directly.

Canada has been pursuing trade deals with other nations – Comprehensive Economic and Trade Agreement (CETA) and the Trans-Pacific Partnership (TPP) – and Canada will benefit from more diverse trade relations. However, the fruits of these deals may not be seen until well after any pain from a trade disruption with the United States. The province faces short term trade risks.

Ontario has experienced more broad based growth which should continue over the forecast horizon. Consumer spending and investment will continue to drive economic growth over the forecast horizon.

Actual Weather and Demand

Since the last Ontario Demand Forecast document was published actual demand figures for the six months of December through May have been recorded. Demand for all the months except March showed a year over year increase. Part of this was due to the weather, but even after correcting for the variability of weather, demand for the six months was up 1.0% compared to the same months a year previous. Considering that weather corrected demand dropped by 2.8% annually in 2017, the start to 2018 appears to signal a small rebound in electricity demand.

April 2018 was an interesting month in that it was historically cold for a number of areas within the province. The contrast is very pronounced when compared to April 2017 which set a record in terms of lowest monthly demand since market opening. Not surprisingly, actual demand was up 8.1% on a year over year basis. That value comes

down significantly after correcting for weather as the year over year growth rate is a much lower 1.7%.

For the past six months, distributor loads were up 3.9 percent compared to the same months a year earlier. Distributor loads see the direct impact of conservation and the growth in embedded generation production, which contributes to the year-over-year drop. Once again, after adjusting for weather, the year-over-year change was an increase of 1.3 percent.

Wholesale customers' consumption increased a very modest 0.1 percent compared to the same months a year ago. For the first three months, wholesale customers' consumption was down 0.3% whereas the second three months saw year over year increases of 0.4 percent. Pulp and paper and chemicals led the growth over the past six months with year over year increases of 4.2 percent. Motor vehicle manufacturing lagged, seeing demand drop 0.5 percent.

Peak demand for the winter of 2017-18 was 20,906 MW, an increase over the previous winter's peak of 20,688 MW. After corrected for weather variability the peak was still higher in the most recent winter (21,026 MW) compared to the previous winter (20,830 MW). The 2017-18 winter peak was also lowered due to the action of Industrial Conservation Initiative (ICI) participants. The winter peak was the fourth highest peak of the ICI year (May 2017 to April 2018).

The weather over the course of the winter and spring were colder than normal. There was sustained cold over the latter part of December into the beginning of January when the winter peak occurred. The holidays did blunt some of the impact of the coldest weather of the winter.

Demand Forecast

For this 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 peaks are expected to continue on a downward trajectory over the forecast. Though winter peaks will face downward pressure from gains in lighting efficiency and embedded wind generation, summer peaks will face greater downward pressure from numerous sources – improved air conditioning efficiency, the expanded ICI impacts and growth in solar embedded generation.

Grid-supplied energy demand is expected to show a bit of a rebound in 2018 after a significant decrease in 2017. Data for the first months of 2018 support this.

Table 1: Peak and Energy Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2018	22,076	24,535
Winter 2018-19	21,328	22,235
Summer 2019	22,016	24,460
Year	**Normal Weather Energy (TWh)**	**% Growth in Energy**
2006	152.3	-1.9%
2007	151.6	-0.5%
2008	148.9	-1.8%
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 (Forecast)	133.6	1.0%
2019 (Forecast)	134.0	0.3%

- End of Section

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1.0 Introduction

1.1 Outlook Documents

The Ontario Electricity Market Rules (Chapter 5 Section 7.1) require that a demand forecast for the next 18 months be produced and published on a quarterly basis. This Ontario Demand Forecast meets that requirement and covers the period from July 2018 to December 2019. It supersedes the previous forecast released in March 2018 and the previous Ontario Demand Forecast document released in December 2017.

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 document "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_2018jun.pdf. Readers may envision other scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgement 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 2017. 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 18-Month Outlook Tables (http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlooktables_2018jun.xls) spreadsheet posted alongside the Outlook documents. The spreadsheet's historical tables contain data 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 the 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 and weather scenarios are available upon request.

- End of Section -

2.0 Demand Forecast

This section presents the demand forecast for the Outlook period. Additional tables are included in the 18-Month 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 the 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)	Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
03-Jun-18	18,983	21,380	1,292	2,361	24-Mar-19	17,872	18,735	569	2,520
10-Jun-18	19,621	23,852	1,055	2,503	31-Mar-19	17,887	18,991	567	2,528
17-Jun-18	20,463	23,830	835	2,519	07-Apr-19	17,567	18,170	471	2,464
24-Jun-18	21,890	24,189	754	2,582	14-Apr-19	16,836	17,943	496	2,402
01-Jul-18	21,790	23,734	1,016	2,616	21-Apr-19	16,403	16,724	531	2,322
08-Jul-18	22,076	24,535	814	2,612	28-Apr-19	16,391	16,501	721	2,332
15-Jul-18	22,023	23,358	838	2,682	05-May-19	17,502	19,935	849	2,315
22-Jul-18	21,424	23,450	1,035	2,585	12-May-19	16,620	19,397	845	2,322
29-Jul-18	21,351	24,249	841	2,660	19-May-19	18,280	21,518	1,175	2,350
05-Aug-18	21,946	24,292	958	2,692	26-May-19	17,982	21,703	1,330	2,299
12-Aug-18	21,665	24,257	985	2,657	02-Jun-19	18,694	21,236	1,292	2,362
19-Aug-18	20,847	24,029	1,362	2,634	09-Jun-19	19,434	23,708	1,055	2,515
26-Aug-18	20,899	22,981	1,413	2,615	16-Jun-19	20,214	23,642	835	2,530
02-Sep-18	20,110	22,666	1,370	2,508	23-Jun-19	21,484	24,039	754	2,593
09-Sep-18	18,626	22,050	680	2,360	30-Jun-19	21,523	23,516	1,016	2,625
16-Sep-18	19,013	21,319	781	2,426	07-Jul-19	22,016	24,460	814	2,619
23-Sep-18	17,632	20,300	420	2,392	14-Jul-19	21,533	23,222	838	2,688
30-Sep-18	17,002	18,866	554	2,340	21-Jul-19	21,095	23,322	1,035	2,589
07-Oct-18	17,257	17,528	786	2,377	28-Jul-19	21,115	24,011	841	2,664
14-Oct-18	17,097	17,485	507	2,355	04-Aug-19	21,846	24,434	958	2,699
21-Oct-18	17,374	17,922	392	2,399	11-Aug-19	21,548	24,282	985	2,669
28-Oct-18	17,491	18,140	318	2,441	18-Aug-19	20,747	23,882	1,362	2,648
04-Nov-18	17,799	18,482	416	2,455	25-Aug-19	20,707	22,739	1,413	2,624
11-Nov-18	18,734	19,331	601	2,552	01-Sep-19	19,961	22,469	1,370	2,521
18-Nov-18	18,980	19,877	342	2,564	08-Sep-19	18,524	21,889	680	2,370
25-Nov-18	19,421	20,327	607	2,639	15-Sep-19	18,890	20,647	781	2,438
02-Dec-18	19,752	20,942	409	2,680	22-Sep-19	17,472	19,595	420	2,404
09-Dec-18	19,911	21,209	555	2,709	29-Sep-19	16,898	18,215	554	2,354
16-Dec-18	20,450	21,446	690	2,761	06-Oct-19	17,129	17,151	786	2,391
23-Dec-18	20,220	21,416	362	2,742	13-Oct-19	16,982	17,165	507	2,414
30-Dec-18	18,993	19,587	528	2,530	20-Oct-19	17,242	17,740	392	2,366
06-Jan-19	20,867	22,163	570	2,785	27-Oct-19	17,371	17,961	318	2,454
13-Jan-19	21,328	22,235	547	2,861	03-Nov-19	17,659	18,300	416	2,472
20-Jan-19	20,826	21,628	483	2,850	10-Nov-19	18,565	19,111	601	2,563
27-Jan-19	20,727	21,743	404	2,857	17-Nov-19	18,816	19,665	342	2,574
03-Feb-19	20,735	21,872	734	2,864	24-Nov-19	19,259	20,113	607	2,650
10-Feb-19	19,929	21,348	635	2,799	01-Dec-19	19,588	20,734	409	2,688
17-Feb-19	19,718	21,188	581	2,751	08-Dec-19	19,726	20,980	555	2,720
24-Feb-19	19,325	21,113	501	2,701	15-Dec-19	20,303	21,247	690	2,776
03-Mar-19	20,026	21,204	531	2,739	22-Dec-19	20,100	21,247	362	2,757
10-Mar-19	19,398	20,281	649	2,684	29-Dec-19	18,724	19,375	528	2,541
17-Mar-19	18,349	19,194	611	2,607	05-Jan-20	19,177	20,297	570	2,653

Compared to the previous forecast the weekly energy demand is marginally lower in 2018 but then slightly higher in 2019. Weekly peaks are slightly through to the fall of 2018 then lower thereafter.

Figure 2.1: Weekly Energy Demand – History and Forecast

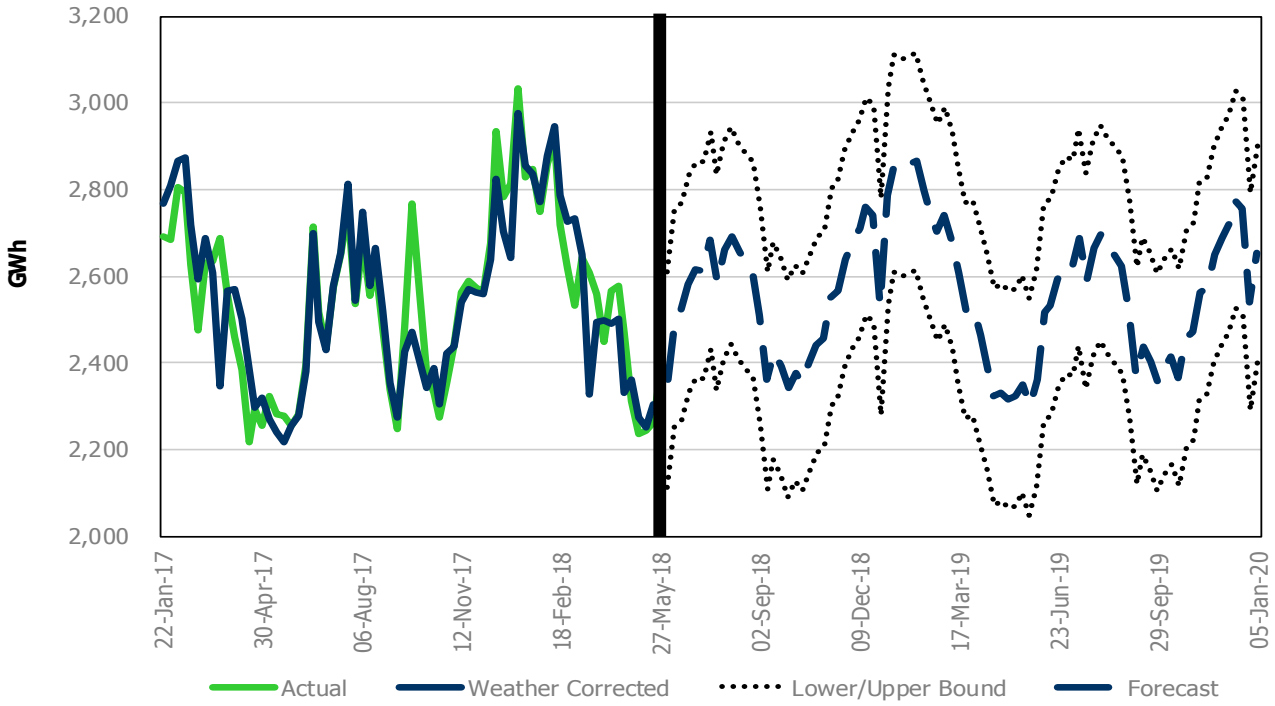
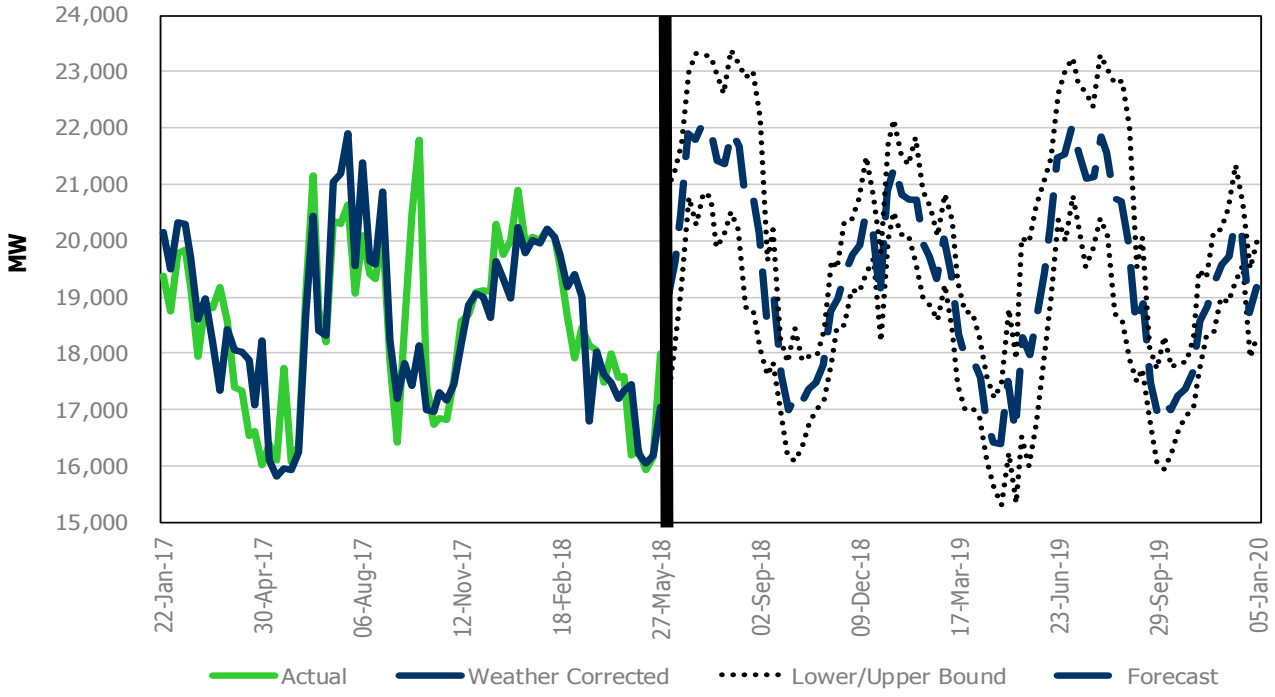


Figure 2.2: Weekly Peak Demand – History and Forecast



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3.0 Historical Review

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

3.1 Six-Month Review – December to May

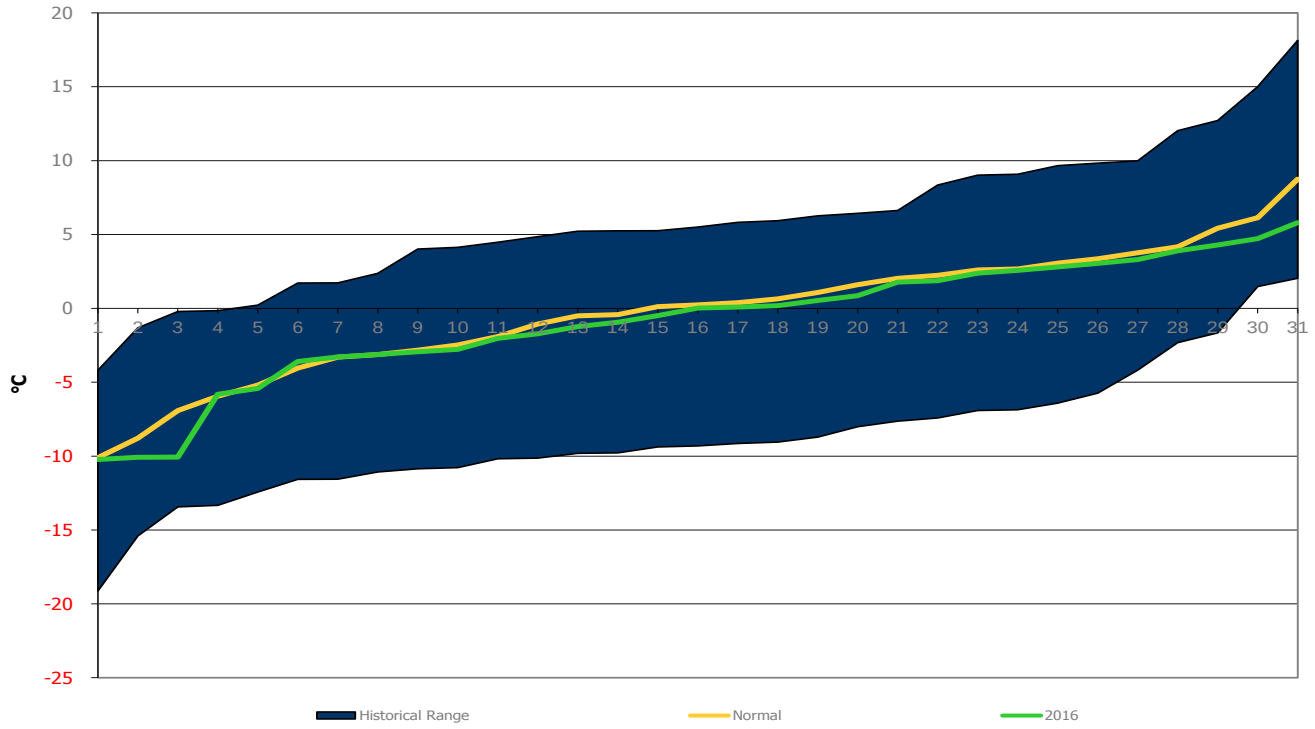
Since the last Ontario Demand Forecast document, actuals have been recorded for the period December to May. Overall, weather for the winter of 2017-18 was near normal, but there were some anomalies across the season. There were some periods of colder than normal weather in January and late December but the milder days of the winter were significantly warmer than normal. Overall the winter was colder than normal. The spring weather was also colder than normal due to a near record cold April.

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

December

The weather experienced throughout Ontario in December 2017 was slightly colder than normal, with several below seasonal days. Based on the monthly average temperature, it was the twenty-third coldest December in the past 50 years. Figure 3.1 presents the ranked range of temperatures for the month. .

Figure 3.1: Daily Temperature - December



The peak occurred on December 11, which was only the thirteenth coldest day of the month with temperatures reaching -4°C (in Toronto). The top six coldest days in December 2017 did not set a demand peak as they occurred over the holiday break, from Boxing Day to New Year's Eve. The month's peak demand of 20,306 MW was lower than the previous December's. Much of this is due to differing peak day temperatures. The weather-corrected peak for December was 21,026 MW.

Energy demand for December 2017 was 12.3 TWh (11.9 TWh weather corrected). The weather corrected values are comparatively low from a historical perspective and consistent with many of the months throughout 2017.

The minimum demand for the month was 12,093 MW, which is on the high side of historical standards. Typically minimum demand levels occur over the holiday period but with the very cold temperatures the minimum occurred on a much warmer Sunday earlier in the month, December 3 at 4 a.m.

Embedded generation for the month was 404 GWh, a decrease of 8.1 percent compared to the previous December. Water and wind output was up, but offset by larger declines in solar and non-contracted generation compared to the previous year.

Wholesale customers' consumption increased by 0.4 percent compared to the previous December. With the exception of pulp and paper, all the major sectors increased their consumption compared to the previous year.

Table 3.1 contains demand data for the month. The table shows observations for the past five years and then includes the historical minimums and maximums. The history covers the time from market opening in May 2002. The historical minimums and maximums include the year in which they occurred.

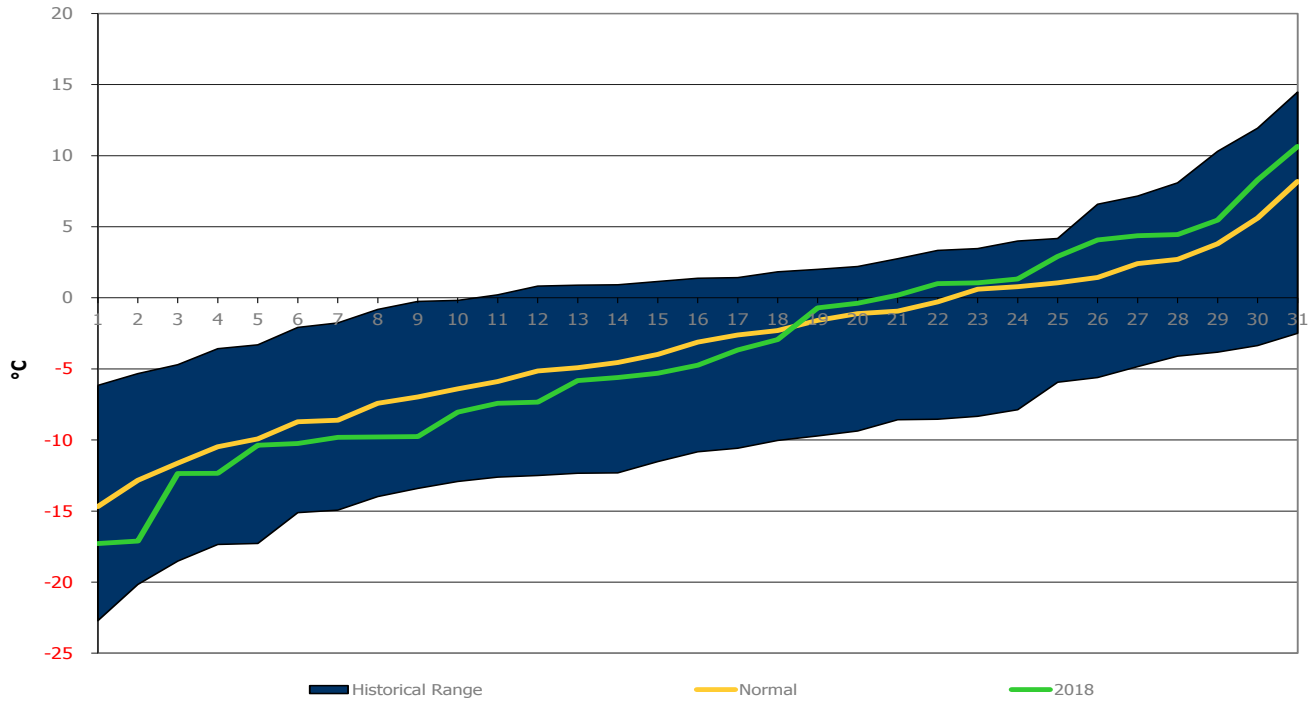
Table 3.1: Demand History – December

December	2017	2016	2015	2014	2013	Historical Minimum	Historical Maximum
Actual Peak (MW)	20,306	20,688	19,161	20,938	22,556	19,161 2015	24,979 2004
Peak Day Temperature (°C)	-4.1	-8.1	6.8	-1.2	-8.3	-12.3 2004	6.8 2015
Weather Corrected Peak (MW)	21,026	20,299	20,155	21,322	22,047	20,155 2015	24,097 2005
Actual Energy (GWh)	12,273	11,948	11,335	12,163	12,805	11,335 2015	13,982 2004
Monthly Average Temperature (°C)	-2.2	0.3	6.3	1.8	-2.1	-2.2 2017	6.3 2015
Weather Corrected Energy (GWh)	11,891	11,923	12,083	12,363	12,532	11,891 2017	13,837 2004
Minimum Demand (MW)	12,093	11,684	10,811	11,398	12,626	10,811 2015	14,169 2004
Embedded Generation (GWh)	404	440	436	426	329	151 2007	440 2016
Wholesale Consumption (GWh)	1,407	1,402	1,388	1,424	1,444	1,225 2009	2,023 2002

January

January 2018 was colder than normal. The cold weather from the end of December carried into the beginning of January. Milder temperatures later in the month moderated the monthly average temperature. Figure 3.2 shows the temperature for January 2018 against historical ranges.

Figure 3.2: Daily Temperature – January



The month's peak demand occurred on Friday, January 5, which was the second coldest day of the month. The coldest day was the following day, Saturday, January 6. However, since it occurred over a weekend it was unlikely to be the monthly demand peak.

The actual peak was 20,906 MW and the weather-corrected peak was 20,229 MW. The actual peak was low by historical standards and the weather-corrected was the lowest January since the market opening in 2002. Class A customers, via the Industrial Conservation Initiative, were active on January 5 reducing their demand and, in turn, the peak demand. Estimates of the reduction due to the ICI program are roughly 1,400 MW.

Actual and weather-corrected energy demand for the month was 12.7 TWh.

The minimum demand of 12,453 MW occurred at 4 a.m. on Sunday, January 28. This was one of the warmest days of the month. The minimum was low by historical standards.

Embedded generation for the month was 535 GWh. This represents a 14 percent increase over the previous January. Output from solar (3.7 percent) and water (26.7 percent) were up while wind was down (23.3 percent).

Wholesale customers' consumption decreased 0.6 percent over the previous January. Despite ending the year on a strong note, iron and steel demand slowed in January while the pulp and paper and motor vehicle manufacturing sectors were up over the previous January.

Table 3.2 summarizes demand information for the month.

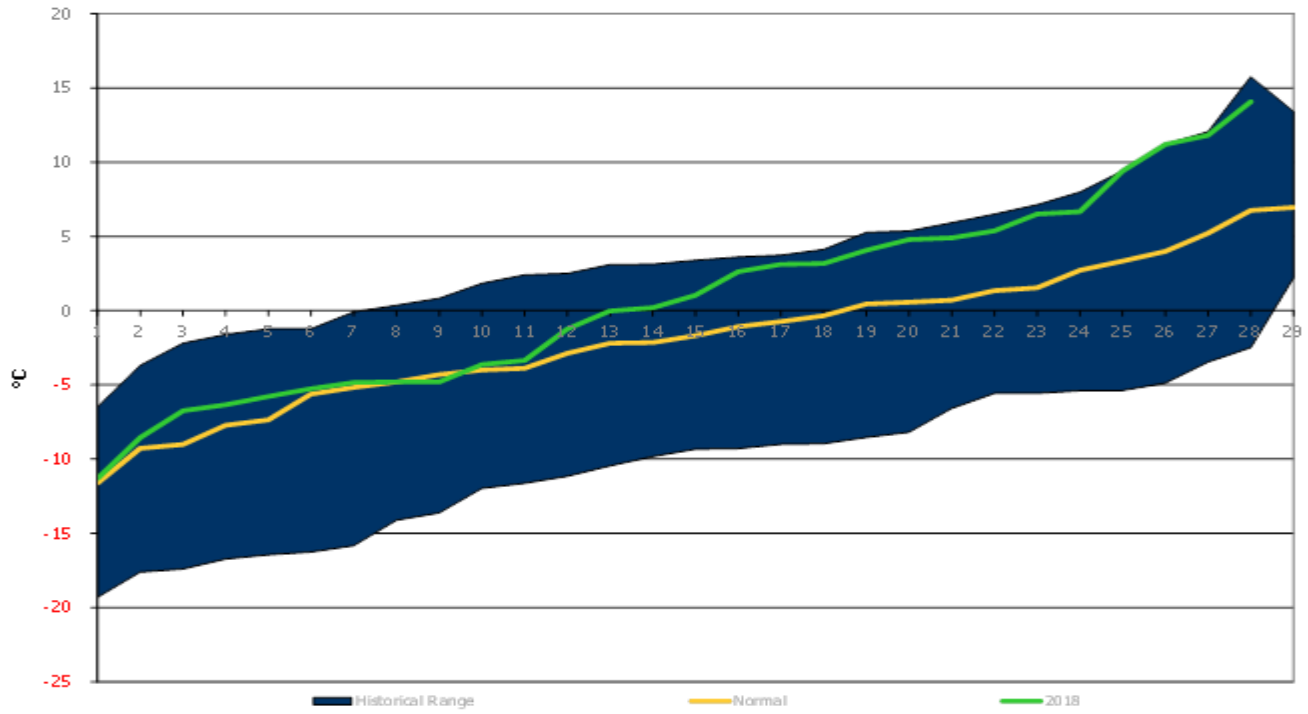
Table 3.2: Demand History – January

January	2018	2017	2016	2015	2014	Historical Minimum	Historical Maximum
Actual Peak (MW)	20,906	20,372	20,836	21,814	22,774	20,372 2017	24,937 2004
Peak Day Temperature (°C)	-15.2	-3.3	-11.8	-15.7	-17.4	-19.7 2004	-3.3 2017
Weather Corrected Peak (MW)	20,229	20,830	21,158	21,531	22,119	20,229 2018	24,409 2004
Actual Energy (GWh)	12,701	12,108	12,385	13,120	13,614	12,108 2017	14,767 2004
Monthly Average Temperature (°C)	-2.7	0.2	-0.5	-4.7	-6.0	-6.9 2004	2.5 2006
Weather Corrected Energy (GWh)	12,683	12,537	12,620	12,843	13,302	12,537 2017	14,521 2005
Minimum Demand (MW)	12,453	12,246	12,116	13,344	13,381	11,835 2011	13,872 2009
Embedded Generation (GWh)	535	469	473	463	400	167 2003	535 2018
Wholesale Consumption (GWh)	1,416	1,425	1,439	1,426	1,473	1,308 2010	2,188 2003

February

Overall, February was warmer than normal. Each month has warm and cold days. For February, the cold days were near normal whereas the milder days were much warmer than normal. This can be seen in Figure 3.3.

Figure 3.3: Daily Temperature - February



The actual peak for the month was 20,076 MW occurring on Monday, February 5. It was the second coldest day of the month. The weather-corrected value was virtually the same at 20,081 MW. Both of these values represent the low values by historical standards.

Energy demand for the month was 11.0 TWh (11.2 TWh weather-corrected). Both are an increase over February 2017 but are low by historical standards.

Minimum demand of 12,716 MW occurred Sunday, February 25 at 3 a.m. This was also one of the warmest days of the month. Once again, it was higher than the previous February, but was otherwise low by historical standards.

Embedded generation topped 497 GWh for the month, which represents an increase of 0.7 percent compared to the previous February. Increases in output from wind (45.1 percent), hydro (12.2 percent) and solar (5.9 percent) were offset by declines in the amount of non-contracted generation reported (-36.5%).

For the second consecutive month, wholesale customers' consumption decreased by 0.6 percent. Chemicals and pulp and paper accounted for the growth while most other major consuming sectors were down.

Table 3.3 summarizes demand information for the month.

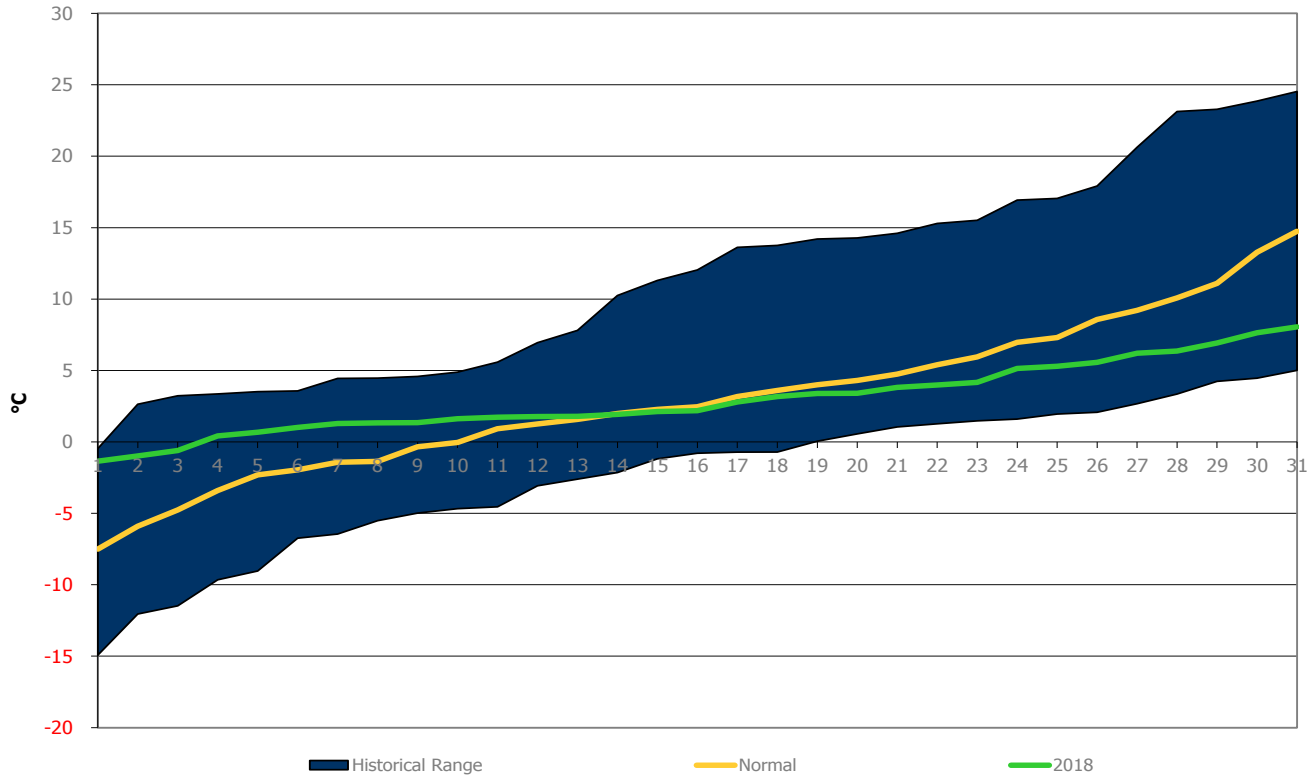
Table 3.3: Demand History – February

February	2018	2017	2016	2015	2014	Historical Minimum	Historical Maximum
Actual Peak (MW)	20,076	19,838	20,766	21,494	21,905	19,838 2017	23,935 2007
Peak Day Temperature (°C)	-8.2	-1.1	-10.0	-15.8	-12.2	-15.8 2015	1.3 2012
Weather Corrected Peak (MW)	20,081	20,306	20,195	20,132	21,541	20,081 2018	23,434 2007
Actual Energy (GWh)	10,951	10,608	11,472	12,302	12,067	10,608 2017	13,123 2003
Monthly Average Temperature (°C)	1.5	2.6	1.1	-9.3	-5.1	-9.3 2015	2.6 2017
Weather Corrected Energy (GWh)	11,226	10,970	11,593	11,468	11,727	10,970 2017	13,173 2004
Minimum Demand (MW)	12,716	11,867	12,533	14,588	13,981	11,867 2017	14,894 2007
Embedded Generation (GWh)	497	493	478	400	336	165 2009	497 2018
Wholesale Consumption (GWh)	1,319	1,327	1,368	1,328	1,393	1,242 2009	1,981 2003

March

The weather experienced throughout March was unusual in that there was not much variation. The cold days were milder than normal and the warmer days were colder than normal. Overall, temperatures were pretty consistent. This can be seen in Figure 3.4 shows the historical range of temperatures for the month.

Figure 3.4: Daily Temperature – March



The peak occurred on March 6, which was only the sixth coldest day of the month. Though as mentioned previously, there was not a lot of temperature variation across the month and the difference between coldest day and the peak day was only two degrees. Since it was milder than normal, the weather-corrected peak was higher at 19,934 MW, reflecting the warmer than normal temperatures.

Energy demand for March 2018 was 11.3 TWh (11.2 TWh weather corrected). The weather-corrected value is a historic low.

The minimum demand for the month was 12, 158 MW, which is on the high side of historical standards and the exact same number as last March. The minimum occurred later in the month at 3 a.m. on Good Friday.

Embedded generation for the month was 597 GWh, an increase of 6.4 percent compared to the previous March. Water and non-contracted output were up offsetting declines for the other fuels (solar, wind and bio-fuel).

Wholesale customers' consumption increased by 0.3 percent compared to the previous March. With the exception of vehicle manufacturing, all the major sectors increased their consumption compared to the previous year.

Table 3.4 summarizes demand information for the month.

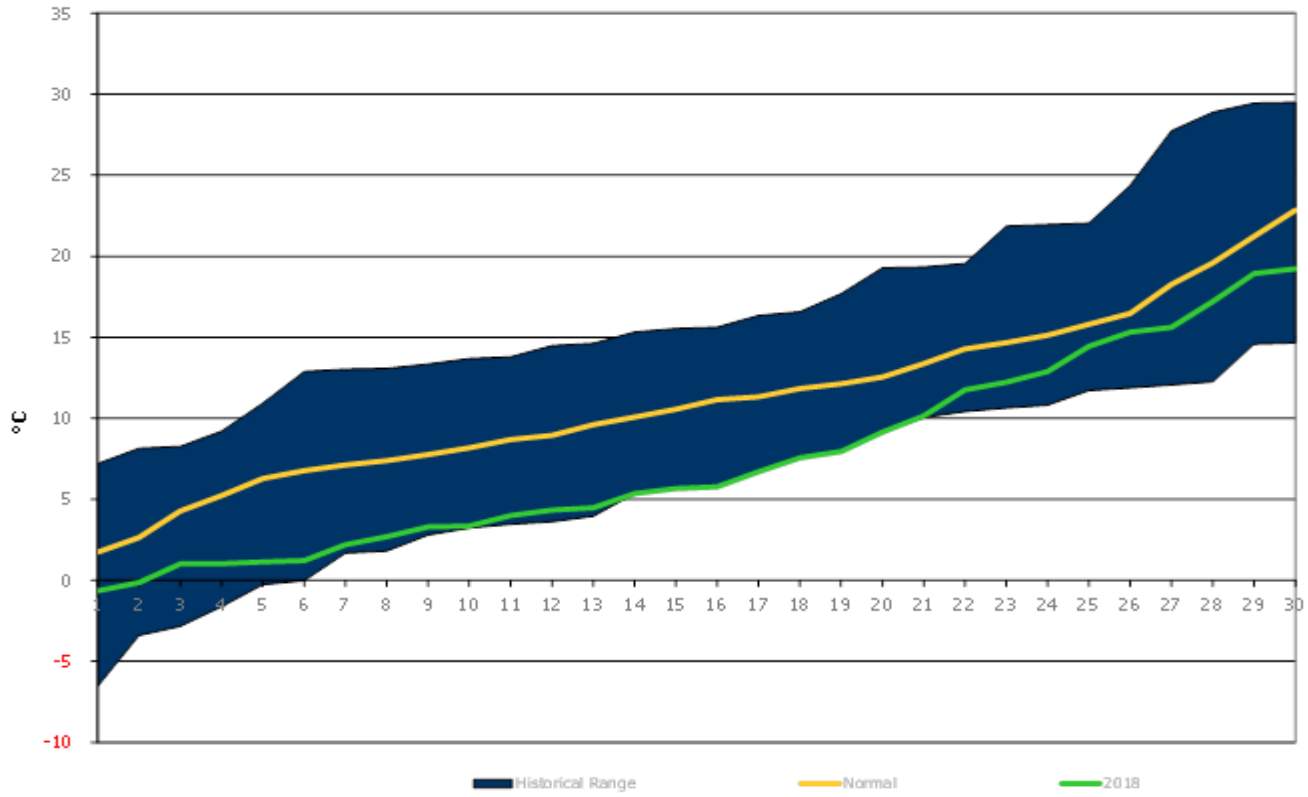
Table 3.4: Demand History – March

March	2018	2017	2016	2015	2014	Historical Minimum	Historical Maximum
Actual Peak (MW)	18,462	19,174	20,063	20,827	21,656	18,462 2018	23,117 2003
Peak Day Temperature (°C)	0.2	-8.1	-7.9	-9.6	-12.1	-14.3 2003	2.0 2010
Weather Corrected Peak (MW)	19,394	18,986	20,153	20,070	20,654	18,986 2017	22,667 2005
Actual Energy (GWh)	11,372	11,591	11,303	12,045	12,672	11,303 2016	13,494 2005
Monthly Average Temperature (°C)	3.5	2.8	6.0	2.0	-0.3	-0.3 2014	11.4 2012
Weather Corrected Energy (GWh)	11,209	11,324	11,532	11,570	11,983	11,209 2018	13,288 2005
Minimum Demand (MW)	12,158	12,158	11,717	12,675	13,296	11,250 2012	13,959 2005
Embedded Generation (GWh)	597	561	530	495	436	130 2007	597 2018
Wholesale Consumption (GWh)	1,480	1,477	1,451	1,452	1,543	1,346 2010	2,192 2003

April

April 2018 set records for being cold. It was the coldest April on record for Hamilton and set records going back decades for other areas. Temperatures were consistently colder than normal throughout the whole month. Figure 3.5 shows the values for April 2018 against the historical backdrop. The graph clearly shows that April was indeed colder than normal.

Figure 3.5: Daily Temperature - April



The month's peak demand occurred on Wednesday, April 4, which was the tenth coldest day of the month. The coldest days of the month fell ten days later on a weekend and were therefore not a peak. April is generally a cold peaking month but the correlation between temperature and peaks is not as strong as during the winter. Temperature variations across the province can account for the difference.

The actual peak was 18,011 MW and the weather-corrected peak was 17,489 MW. The actual peak was low by historical standards and the weather-corrected peak was the lowest by historical standards whereas the actual was higher due to the cold weather.

Actual energy demand for the month was 10.6 TWh and weather-corrected energy demand was 10.4 TWh. Both of these demand figures were increases over April 2017, but low by historical standards.

The minimum demand of 11,497 MW occurred at 3 a.m. on Monday, April 23. This was one of the second warmest days of the month. The minimum was unusual in that it occurred on a weekday.

Embedded generation for the month was 585 GWh. This represents a 1.4 percent decline compared to the previous over the previous April. Solar output was up 14% but all other forms of embedded generation were down.

Wholesale customers' consumption increased 0.5 percent over the previous April. The increase was widespread across most of the major energy consuming industrial classes.

Table 3.5 summarizes demand information for the month.

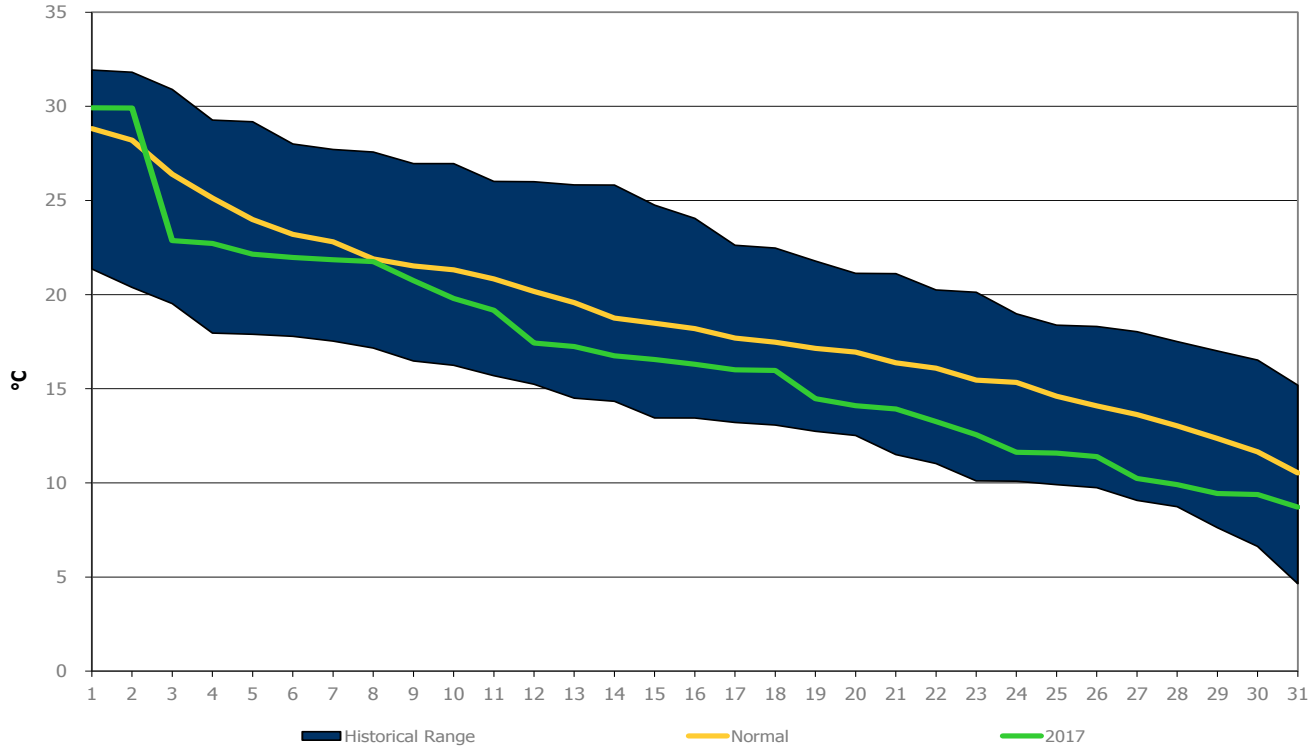
Table 3.5: Demand History – April

April	2018	2017	2016	2015	2014	Historical Minimum	Historical Maximum
Actual Peak (MW)	18,011	17,349	17,821	18,462	18,557	17,349 2017	21,010 2003
Peak Day Temperature (°C)	2.4	7.3	0.6	2.4	-0.9	-1.8 2003	14.1 2008
Weather Corrected Peak (MW)	17,489	18,217	18,292	18,900	18,476	17,489 2018	20,932 2005
Actual Energy (GWh)	10,578	9,789	10,410	10,405	10,837	9,789 2017	12,097 2003
Monthly Average Temperature (°C)	7.1	13.5	8.9	12.1	10.3	7.1 2018	15.4 2010
Weather Corrected Energy (GWh)	10,363	10,171	10,440	10,547	10,922	10,171 2017	12,209 2005
Minimum Demand (MW)	11,497	10,167	11,286	10,975	11,944	10,167 2017	12,427 2004
Embedded Generation (GWh)	585	594	660	652	477	155 2007	660 2016
Wholesale Consumption (GWh)	1,368	1,362	1,436	1,404	1,458	1,224 2009	2,089 2003

May

The weather for May was generally cooler than normal but the peak weather was warmer than normal. Figure 3.6 shows this graphically.

Figure 3.6: Daily Temperature - May



The actual peak for the month was 20,473 MW occurring on Monday, May 28. It was the hottest day of the month. The weather-corrected value was lower at 19,076 MW. Both the actual and weather-corrected were the highest May values since 2012.

Energy demand for the month was 10.4 TWh (10.3 TWh weather-corrected). These values are a slight increase over the past two Mays.

Minimum demand of 10,541 MW occurred Sunday, May 6 at 3 a.m. This was a one of the cooler days for the month. This value is consistent with May minimums since the 2009 recession.

Reported embedded generation topped 661 GWh for the month, which represents an increase of 6.7 percent compared to the previous May. Increases in output from solar (2.7 percent) and non-contracted (144.0 percent) offset declines in wind (-29.3), hydro (32.6) and biogas (9.0).

Wholesale customers' consumption increased 0.4 percent compared to the previous May. Pulp and paper and iron and steel were the sectors driving the growth this month.

Table 3.6 summarizes demand information for the month.

Table 3.6: Demand History – May

May	2018	2017	2016	2015	2014	Historical Minimum	Historical Maximum
Actual Peak (MW)	20,473	17,738	19,885	19,158	18,844	17,560 2009	24,857 2006
Peak Day Temperature (°C)	30.7	29.6	27.2	28.8	29.4	13.1 2003	32.8 2006
Weather Corrected Peak (MW)	19,076	16,886	19,663	18,033	18,705	16,886 2017	21,889 2006
Actual Energy (GWh)	10,421	10,153	10,471	10,547	10,643	10,153 2017	11,927 2006
Monthly Average Temperature (°C)	22.3	16.2	19.8	21.6	18.6	15.7 2002	22.3 2018
Weather Corrected Energy (GWh)	10,292	10,030	10,198	10,401	10,634	10,030 2017	11,824 2006
Minimum Demand (MW)	10,541	10,249	10,461	10,657	10,719	10,249 2017	12,092 2002
Embedded Generation (GWh)	661	619	664	529	484	148 2002	664 2016
Wholesale Consumption (GWh)	1,396	1,391	1,399	1,412	1,446	1,251 2009	2,115 2003

Table 3.3.2 of the 18-Month Outlook Tables spreadsheet contains monthly demand information going back to market-opening.

3.2 Historical Energy Demand

The six-month period can be broken down into its two main components, winter (December, January and February) and spring (March, April and May).

Overall, the winter weather was mixed with February milder, January slightly colder and December pretty normal. Overall it would be slightly colder than normal. Both the actual (up 3.6%) and weather-corrected (up 1.0%) demand increased over the previous winter.

Distributors' loads increased 4.6% over the previous winter. After correcting for the variation in weather, loads increased 1.0%. Further impacting distributor loads are the impacts of embedded generation. For the winter, embedded generation was up 2.4 percent compared to the previous winter. Increases in hydro output (up 27.9%) and wind (8.1) offset reductions in solar, biomass and non-contracted generation.

For the three months, wholesale customers' consumption posted a decline of 0.3 percent compared to the previous winter. Mining was the only sector of the big six (Mining, Pulp and Paper, Chemicals, Refining, Iron and Steel and Motor Vehicle Manufacturing) that showed a year over year decline. However, since it is the largest sector the declines in mining outweighed the growth in the remaining five.

Since the recession, there has been a shift in the economy towards less energy intensive industries such as construction, finance, retail and technology while demand from the traditionally energy intensive industries has remained relatively flat. Pulp and paper, once the largest industrial load in the province continues to face downward pressure due to shifting consumer demand. Sales of newsprint continue to decline as more people have shifted to online publication.

The spring of 2018 was colder than normal. Both April and May were colder than normal. As such, energy demand for the spring was up 2.7% compared to the previous spring. However, after adjusting for weather, the year over year increase was 1.0% compared to spring 2017.

Distributors' loads have increased by 3.1 percent over the spring compared to last spring. After making the weather adjustments the increase is 1.1 percent, which stands in contrast to the experience of 2017 which saw loads decline across the year. This increase came at the same time as embedded generation was also increasing by 3.9% over the previous spring.

For the spring months, wholesale loads showed an increase of 0.4 percent compared to the previous spring. Pulp and paper, iron and steel and mining led the growth in electricity demand.

Figure 3.7 shows weather-corrected distributor load and embedded generation output. Though embedded generation shows seasonal volatility, the underlying upward trend is quite evident in the graph. For the year to date, embedded generation is 5.0 percent higher than last year. Year-to-date embedded generation output is 2.9 TWh.

For the six months from December to May, distributors' weather-corrected loads increased by 1.3 percent compared to the same six-month period a year earlier. Embedded generation increased by a same 3.2 percent for the same period.

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

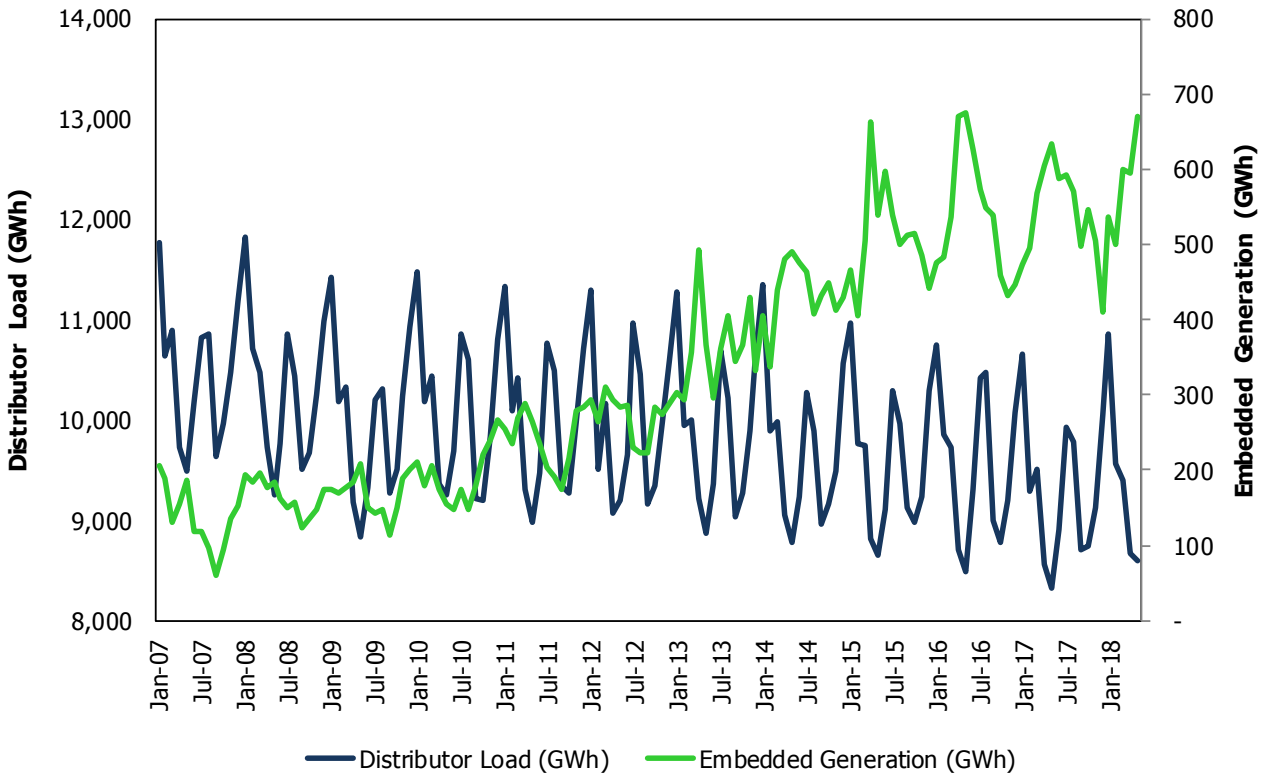


Figure 3.8 shows the year-over-year change in wholesale customers' average hourly consumption. The graph traces the impact of the recession, the short and modest recovery in 2010 and the relatively flat demand since that time.

Figure 3.9 shows the wholesale customers' highest monthly average hourly load by industry segment for 2008 and 2018 year to date (Jan-May).

Mining is the only sector that is higher than its pre-recession value. Pulp and paper, by contrast, has shown the greatest decline but that is attributable to forces within the newsprint market. The other sectors show a similar pattern of having fallen from the pre-recession values and stabilized at a new equilibrium. There has been little movement in industrial demand over the past seven years.

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

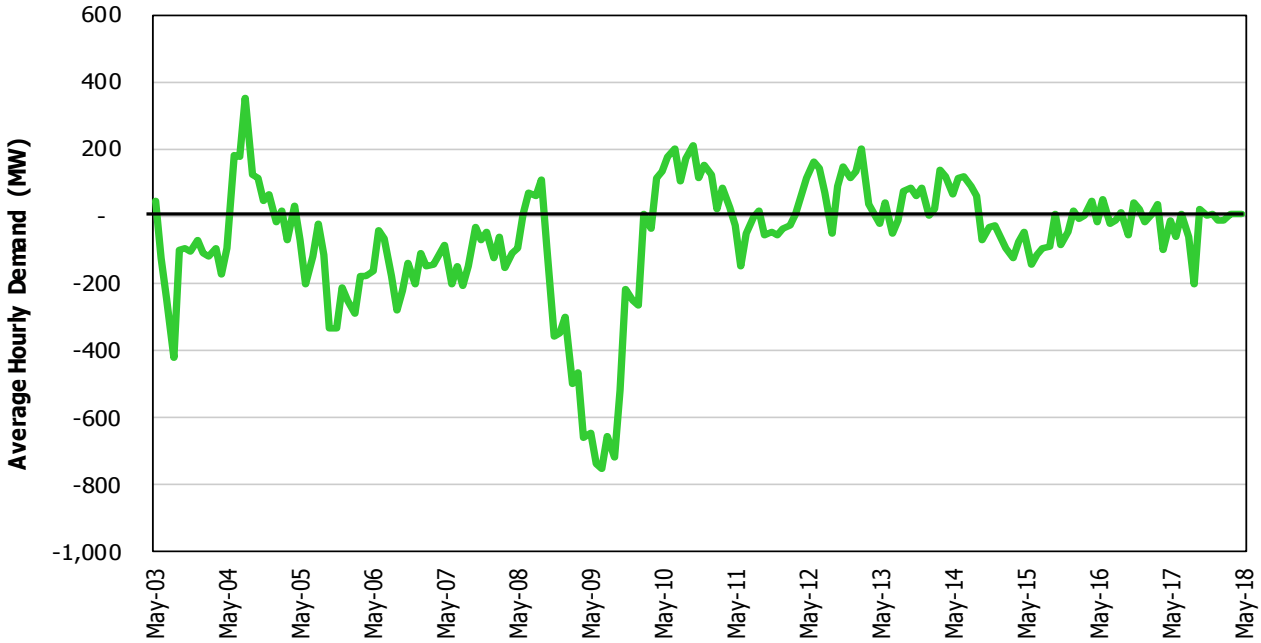


Figure 3.9: Wholesale Customers' Average Hourly Consumption by Industry Segment

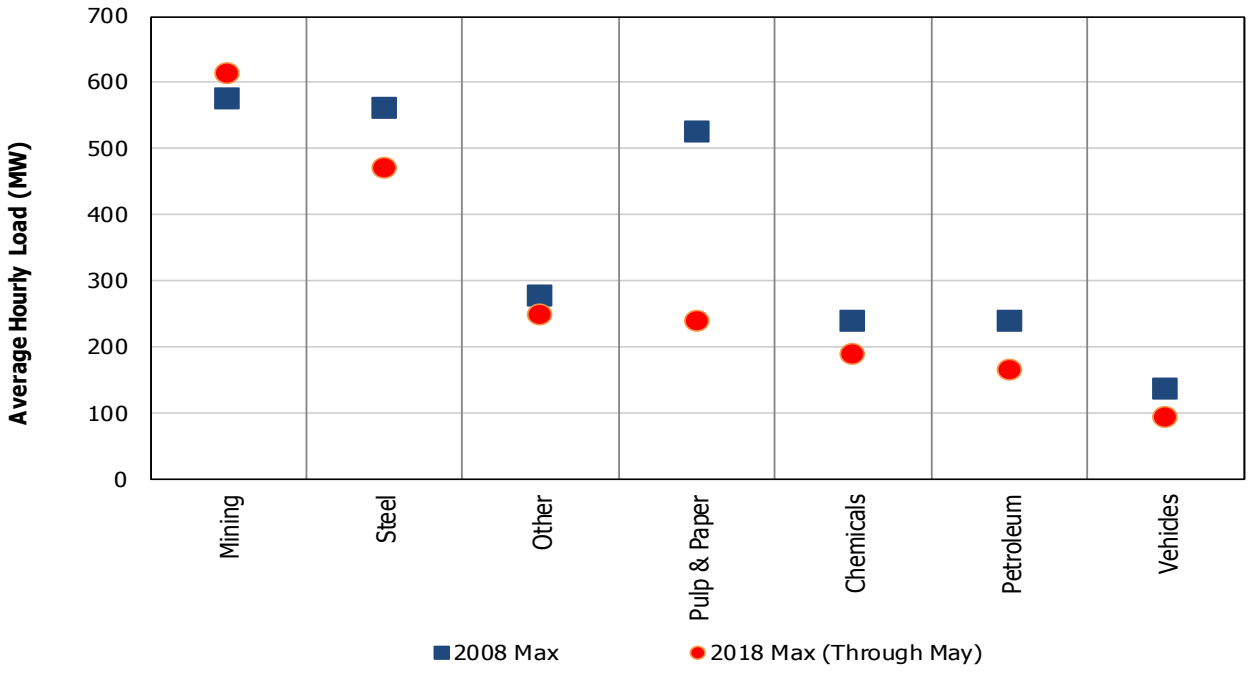


Table 3.7 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week and notes any item of significance for the week. If the weather-corrected demand is greater than the actual demand, it means that the actual weather was milder than normal. Additional history is available in the 18-Month Outlook Tables spreadsheet in Table 3.3.1.

Table 3.7: Historical Weekly Energy Demand

Week Number	Week Ending	Peak Day	Actual Energy (GWh)	Corrected Energy (GWh)	Notes
49	10-Dec-17	07-Dec-17	2,677	2,640	
50	17-Dec-17	11-Dec-17	2,935	2,823	
51	24-Dec-17	18-Dec-17	2,782	2,703	
52	31-Dec-17	28-Dec-17	2,811	2,644	Christmas and Boxing Day
1	07-Jan-18	05-Jan-18	3,032	2,976	New Year's Day
2	14-Jan-18	14-Jan-18	2,830	2,854	
3	21-Jan-18	15-Jan-18	2,845	2,834	
4	28-Jan-18	25-Jan-18	2,746	2,771	
5	04-Feb-18	30-Jan-18	2,859	2,877	
6	11-Feb-18	05-Feb-18	2,914	2,944	
7	18-Feb-18	13-Feb-18	2,718	2,787	
8	25-Feb-18	21-Feb-18	2,620	2,724	Family Day
9	04-Mar-18	02-Mar-18	2,533	2,734	
10	11-Mar-18	06-Mar-18	2,643	2,651	
11	18-Mar-18	14-Mar-18	2,608	2,327	
12	25-Mar-18	20-Mar-18	2,558	2,495	
13	01-Apr-18	27-Mar-18	2,447	2,496	Good Friday
14	08-Apr-18	04-Apr-18	2,565	2,488	Easter Monday
15	15-Apr-18	09-Apr-18	2,576	2,502	
16	22-Apr-18	17-Apr-18	2,470	2,329	
17	29-Apr-18	25-Apr-18	2,311	2,362	
18	06-May-18	02-May-18	2,234	2,273	
19	13-May-18	08-May-18	2,241	2,250	
20	20-May-18	16-May-18	2,263	2,304	
21	27-May-18	25-May-18	2,379	2,304	Victoria Day

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.

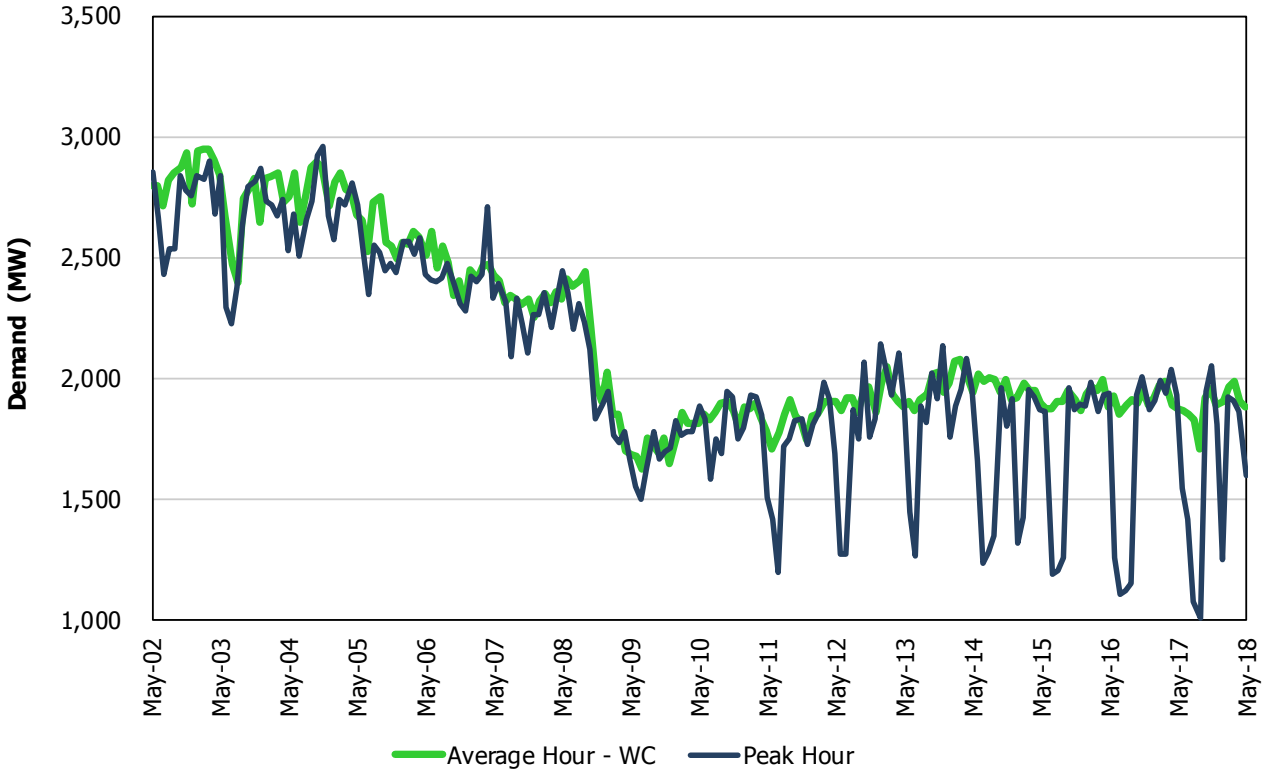
The winter peak was 20,906 MW, which is higher than last winter's peak (20,688 MW). The peak weather was colder than the previous winter. The timing of the cold days can have a significant impact as the holidays act to blunt demand across the end of December and the beginning of January. The weather corrected peak was higher in 2017-18 (21,026 MW) than in 2016-17 (20,830 MW). The difference in the winter peaks was further complicated by the fact that ICI actions reduced the 2017-18 winter peak, whereas the previous winter did not have any ICI impacts.

The spring peak was 20,473 MW which was an increase over spring 2017's peak of 19,174 MW. Of note was the fact that spring 2017 peaked during cold weather in March while spring 2018 peaked during hot weather at the end of May. The weather corrected peak was higher this past spring (19,394 MW) than the previous spring (18,986 MW).

Figure 3.10 shows the wholesale customers' average hourly monthly demand and their consumption at the time coincident with the system peak. It is evident that prior to the ICI program, the average and coincident peak tracked quite closely as many sectors operated 24/7. With the introduction of the program in 2010, wholesale customers have responded by reducing their load during the five peak days. The graph shows a portion of the response. This graph shows the reaction of directly connected customers to the ICI program. The graph does not include the reaction of Class A customers served by distributors.

The program has evolved over time, allowing more loads to participate in the program. At the same time, the financial incentives have also increased. As such, the impact of ICI has grown over time. The recent changes had a disproportionate impact of Class A customers served by distributors and, as such, are not highlighted in this graph.

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



For most years, the province has been summer peaking, but the summer peaks face more downward pressure compared to the winter peaks. In particular, conservation and embedded solar generation do not impact the seasonal peaks to the same degree. The summer peak is primarily driven by air conditioning load, whereas the winter peak is a result of 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 will be zero and have no impact on the winter peak. The summer peak occurs during daylight hours when embedded solar output is significant. This is reducing the summer peaks but is also having an impact of pushing the summer peaks 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 is effectively "carving out" demand in the middle of the day and having the effect of pushing the peak later in the day when solar output is declining more rapidly than demand. This impact is solely occurring in the summer. It is also impacting peaks in the early fall and late spring as well.

Figure 3.11 shows the summer weekday peaks levels in MW and the hour in which they occurred for the summer of 2004, 2014 and the summer of 2017. The graph clearly shows how peaks are both lower and later in the day. The peaks are lower due to conservation and lower industrial demand. Embedded solar generation further reduced the demand in the middle of the day, essentially pushing them down and later in the day. In 2004, there was no embedded solar whereas by 2014 the solar capacity had climbed to 1,200 MW and by 2017 it has reached nearly 2,000 MW of capacity.

Figure 3.11: Seasonal Weekday Peak Hour Distribution - Summer

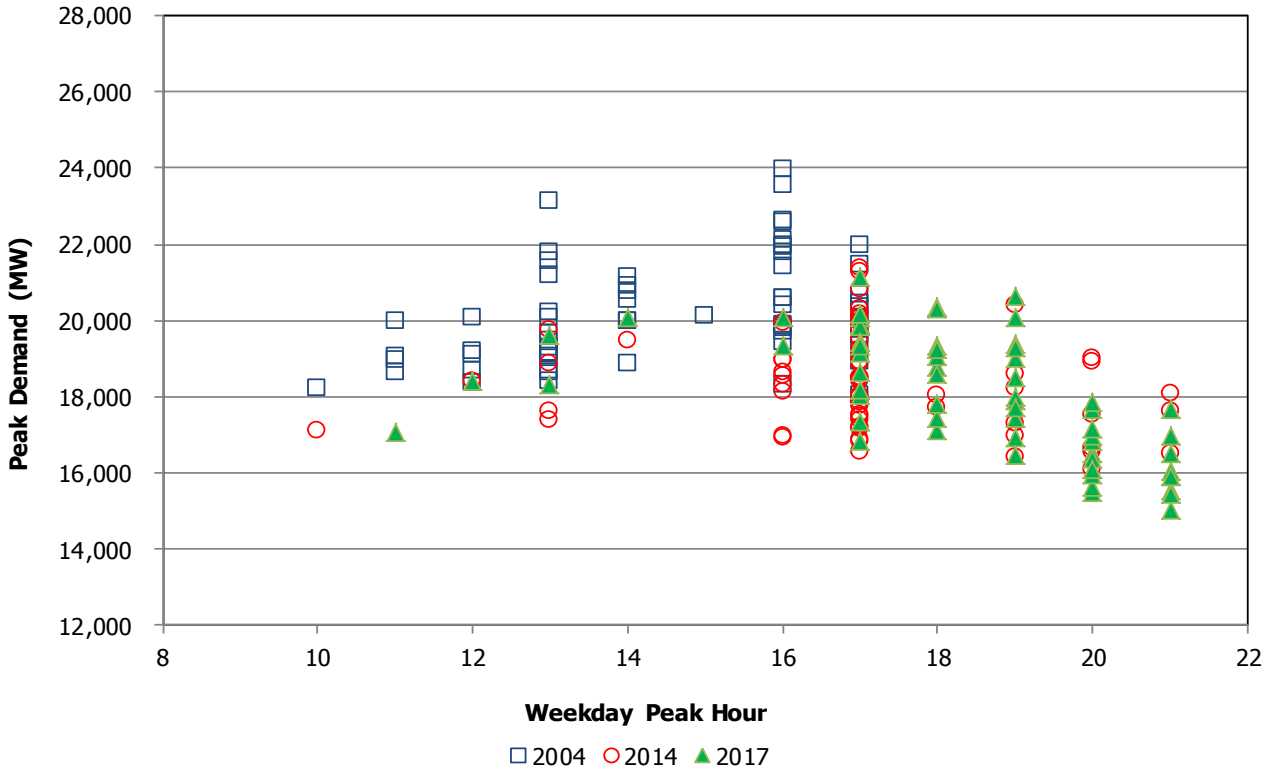


Figure 3.12 shows the weekday peaks in MW and the hour in which they occurred for the fall of 2004, 2014 and 2017. Once again the peaks show the similar pattern of being lower (conservation and lower industrial demand) and later in the day (solar output). The impact of solar will vary across the fall as the daylight in September is different from that in November. However, the effect is similar to that experienced in the summer.

Figure 3.12: Seasonal Weekday Peak Hour Distribution – Fall

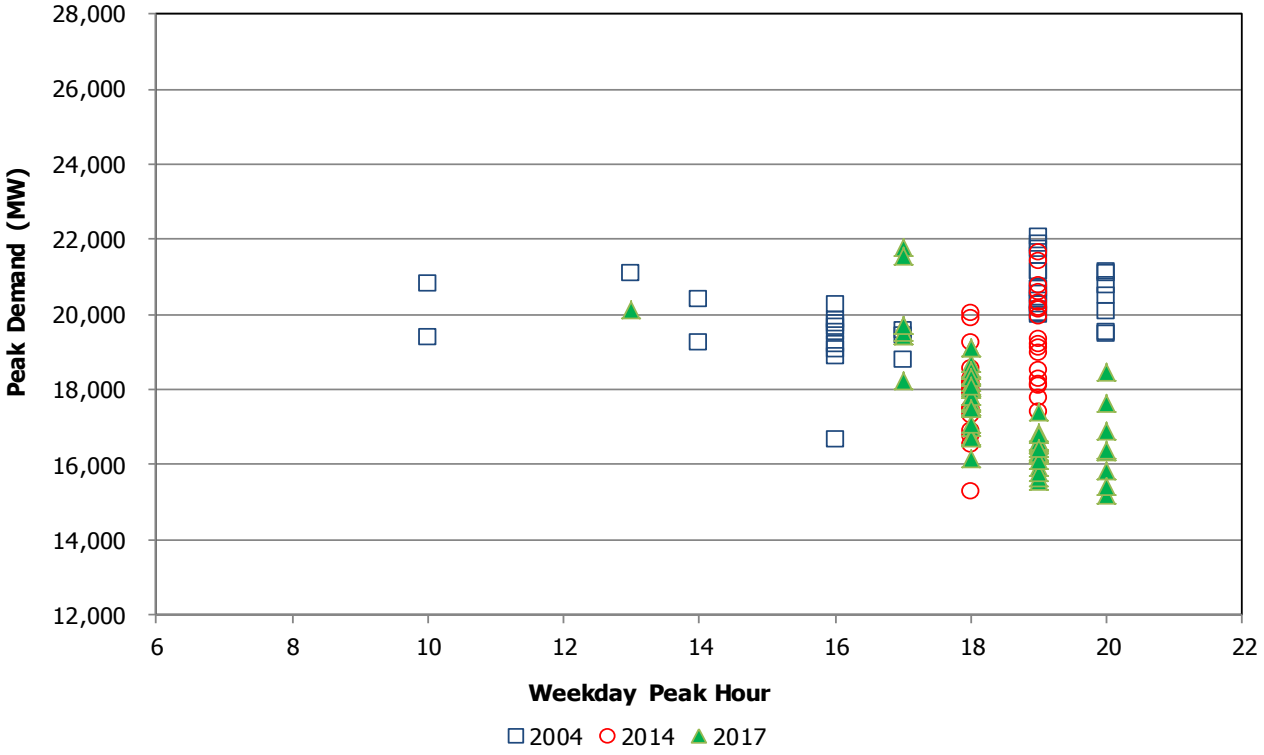


Figure 3.13 shows the weekday peaks in MW and the hour in which they occurred for the winter of 2003-04, 2013-14 and 2017-18. In the winter the peaks occur after sunset. Therefore the impacts of conservation and lower demand are seen in the lower peaks however they are not being pushed later in the day. The exception being a few odd daytime peaks from 2003-4, which have been eliminated by the current solar output.

Figure 3.14 shows the weekday peaks in MW and the hour in which they occurred for the spring of 2004, 2014 and 2018. In 2004, spring time work day peaks occurred in the morning or late afternoon. By 2014 the early impact of solar had started shifting peaks earlier in the morning or later in the day. By 2018, with nearly ten times the solar as 2014, the peaks have been nearly pushed clear of the daylight hours.

Figure 3.13: Seasonal Weekday Peak Hour Distribution – Winter

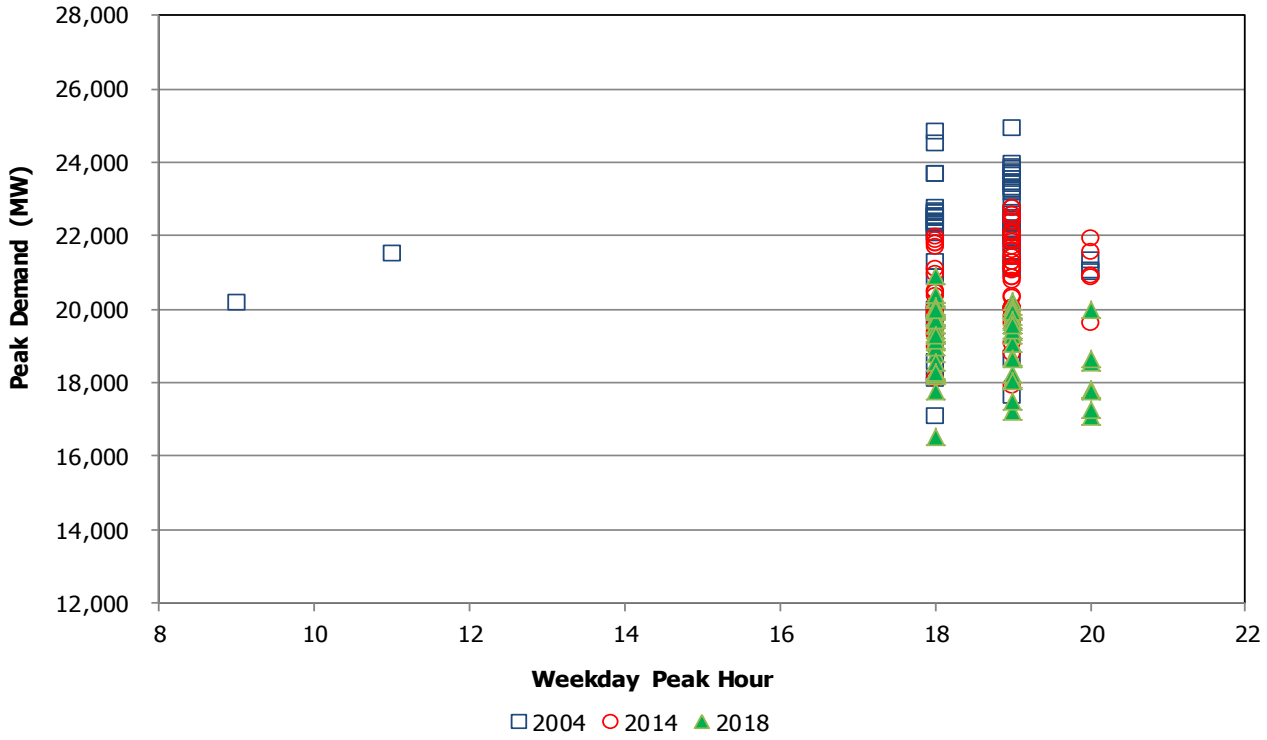


Figure 3.14: Seasonal Weekday Peak Hour Distribution – Spring

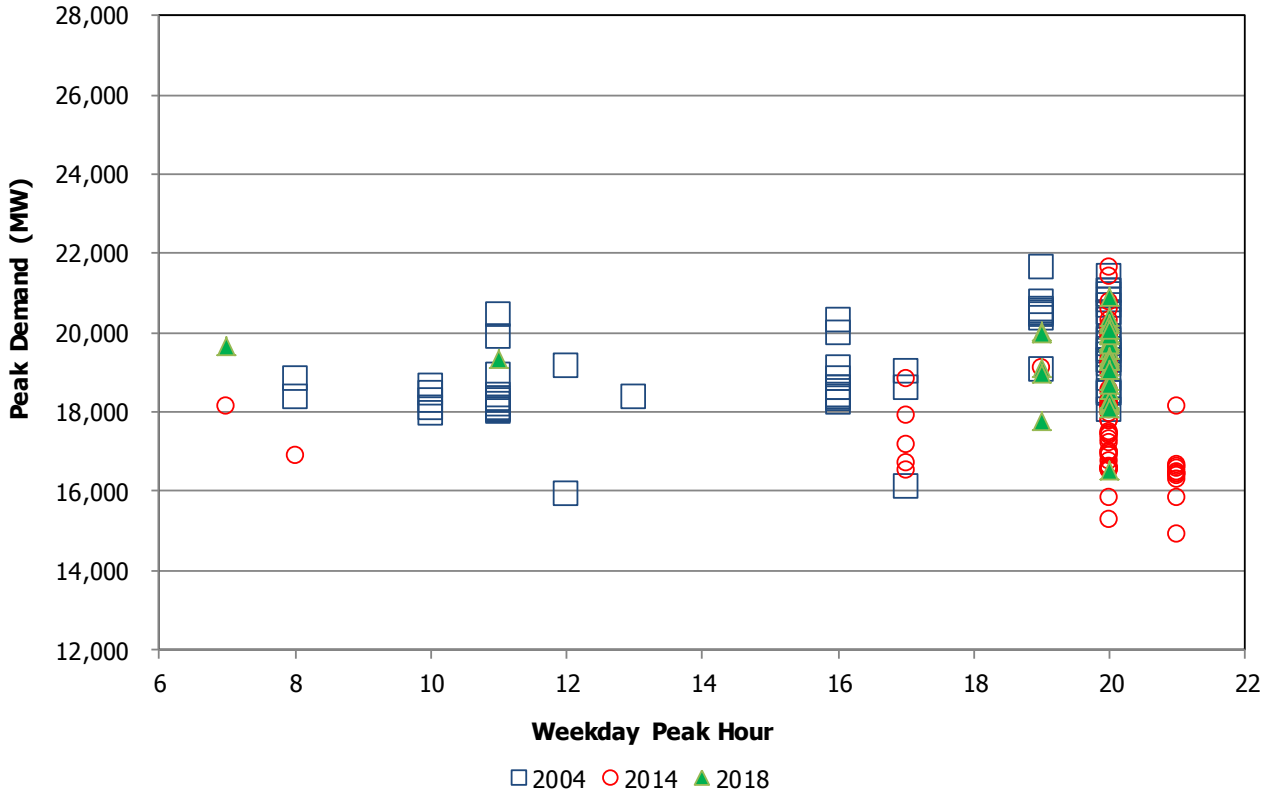


Figure 3.15 shows the break-down for the past winter and summer peaks. For both the peaks, ICI has been a factor. Demand response was activated for the summer peak but not the winter one. Generally, the embedded generation is higher during the summer peak as the significantly larger solar capacity doesn't impact the winter peak which occurs after dark. However, the 2017 summer peak had a lower level of embedded generation output as the peak occurred later in the day, late in September.

Figure 3.15: Anatomy of Seasonal Peaks

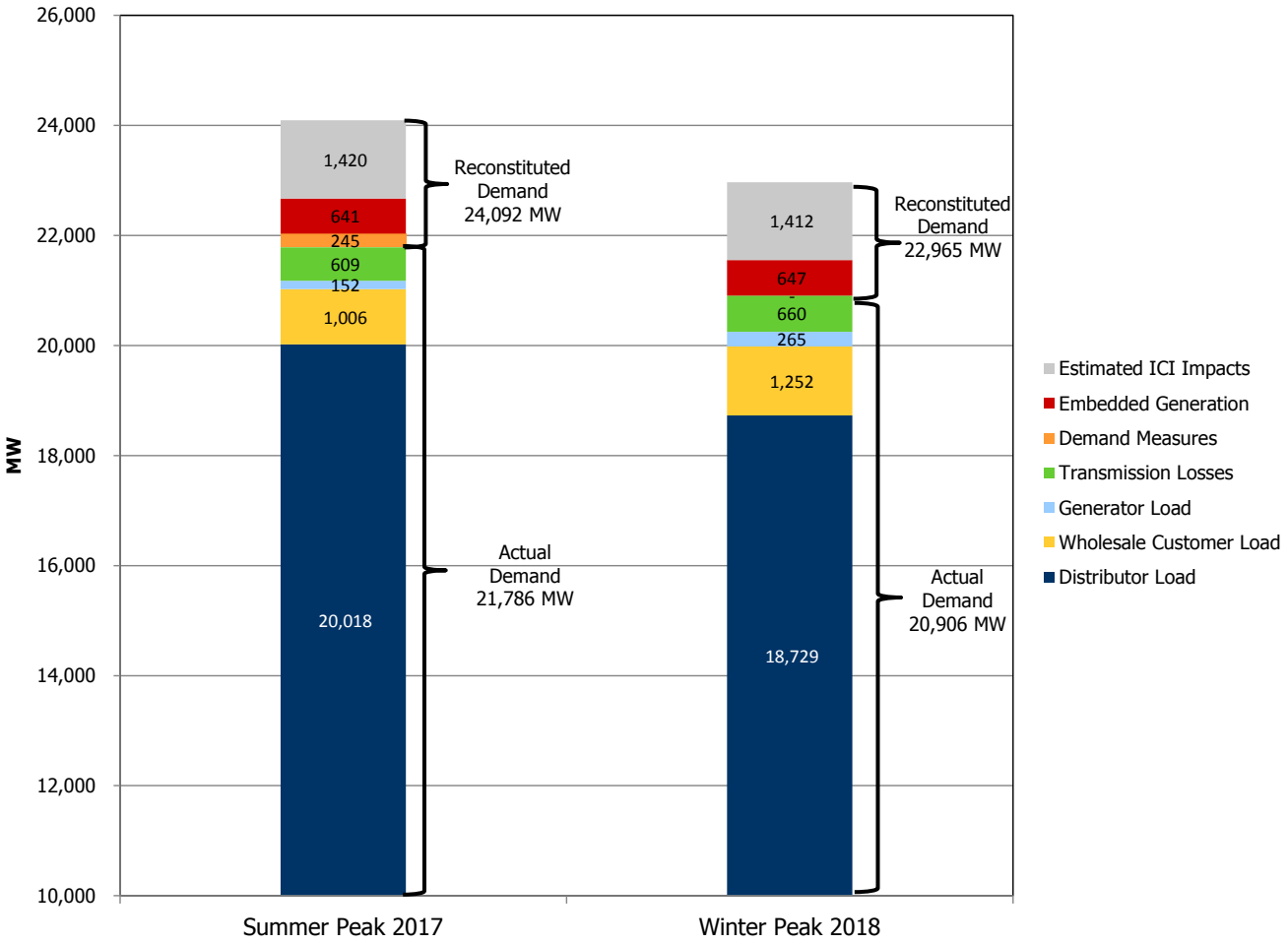


Table 3.3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3.3: Historic Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
49	10-Dec-17	07-Dec-17	19,094	18,631	0.1
50	17-Dec-17	11-Dec-17	20,306	19,621	-4.1
51	24-Dec-17	18-Dec-17	19,743	19,305	2.7
52	31-Dec-17	28-Dec-17	20,008	18,979	-12.8
1	07-Jan-18	05-Jan-18	20,906	20,229	-15.2
2	14-Jan-18	14-Jan-18	19,958	19,791	-6.7
3	21-Jan-18	15-Jan-18	20,073	20,010	-7.3
4	28-Jan-18	25-Jan-18	19,999	19,936	-3.8
5	04-Feb-18	30-Jan-18	20,202	20,220	-8.3
6	11-Feb-18	05-Feb-18	20,076	20,054	-8.2
7	18-Feb-18	13-Feb-18	19,558	19,763	-4.1
8	25-Feb-18	21-Feb-18	18,657	19,179	3.6
9	04-Mar-18	02-Mar-18	17,920	19,394	2.8
10	11-Mar-18	06-Mar-18	18,462	18,989	0.2
11	18-Mar-18	14-Mar-18	18,131	16,789	1.0
12	25-Mar-18	20-Mar-18	18,052	18,023	2.6
13	01-Apr-18	27-Mar-18	17,482	17,635	3.0
14	08-Apr-18	04-Apr-18	18,011	17,489	2.4
15	15-Apr-18	09-Apr-18	17,570	17,184	2.9
16	22-Apr-18	17-Apr-18	17,589	17,323	0.7
17	29-Apr-18	25-Apr-18	16,175	17,453	11.0
18	06-May-18	02-May-18	16,264	16,218	27.5
19	13-May-18	08-May-18	15,933	16,052	18.5
20	20-May-18	16-May-18	16,167	16,193	19.5
21	27-May-18	25-May-18	17,985	17,037	30.2

3.4 Load Duration Curves

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

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 2017 was low by historical standards.

Figure 3.16: Spring Load Duration Curve

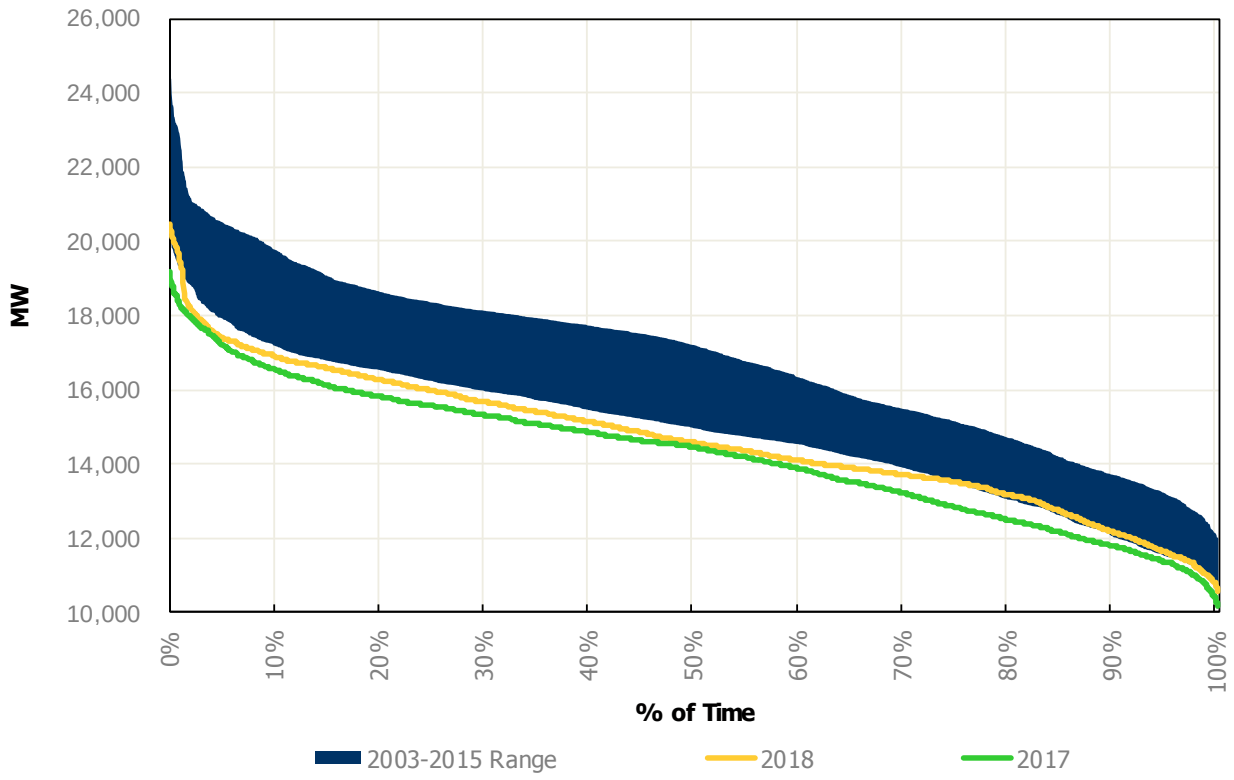


Figure 3.17: Winter Load Duration Curve

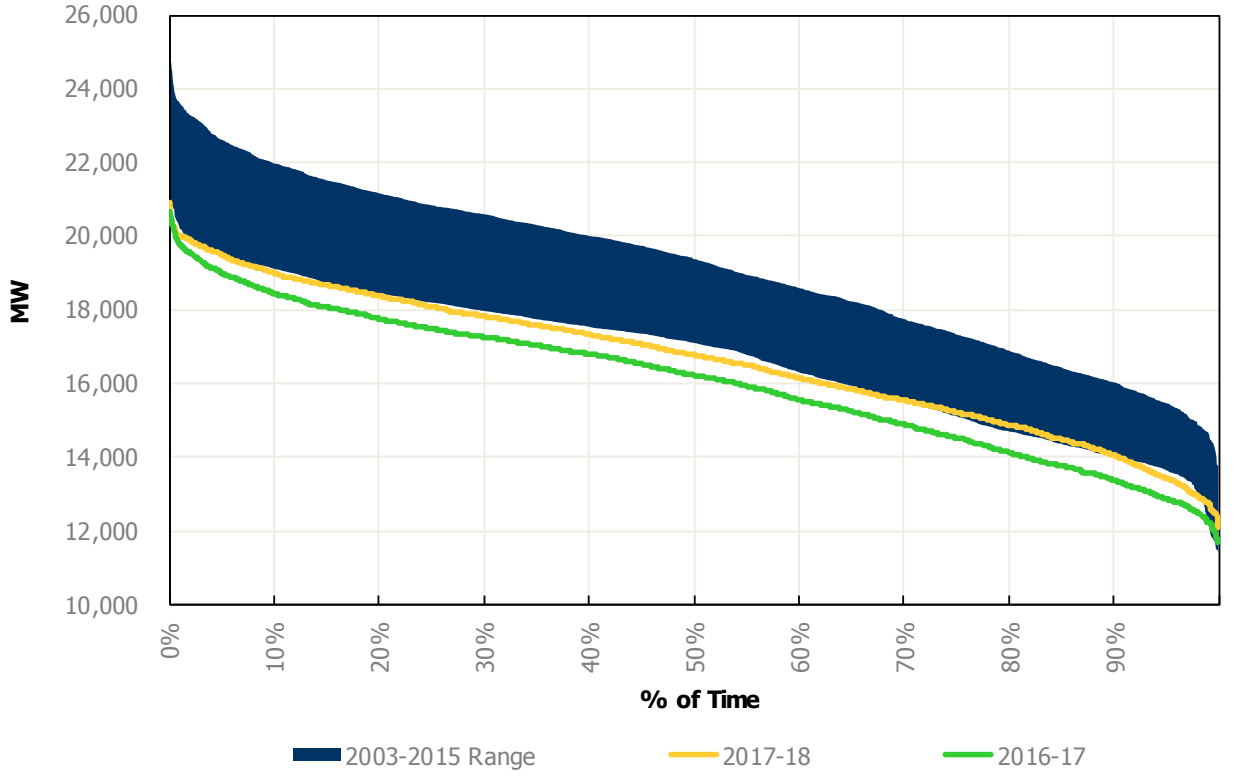


Figure 3.18: Fall Load Duration Curve

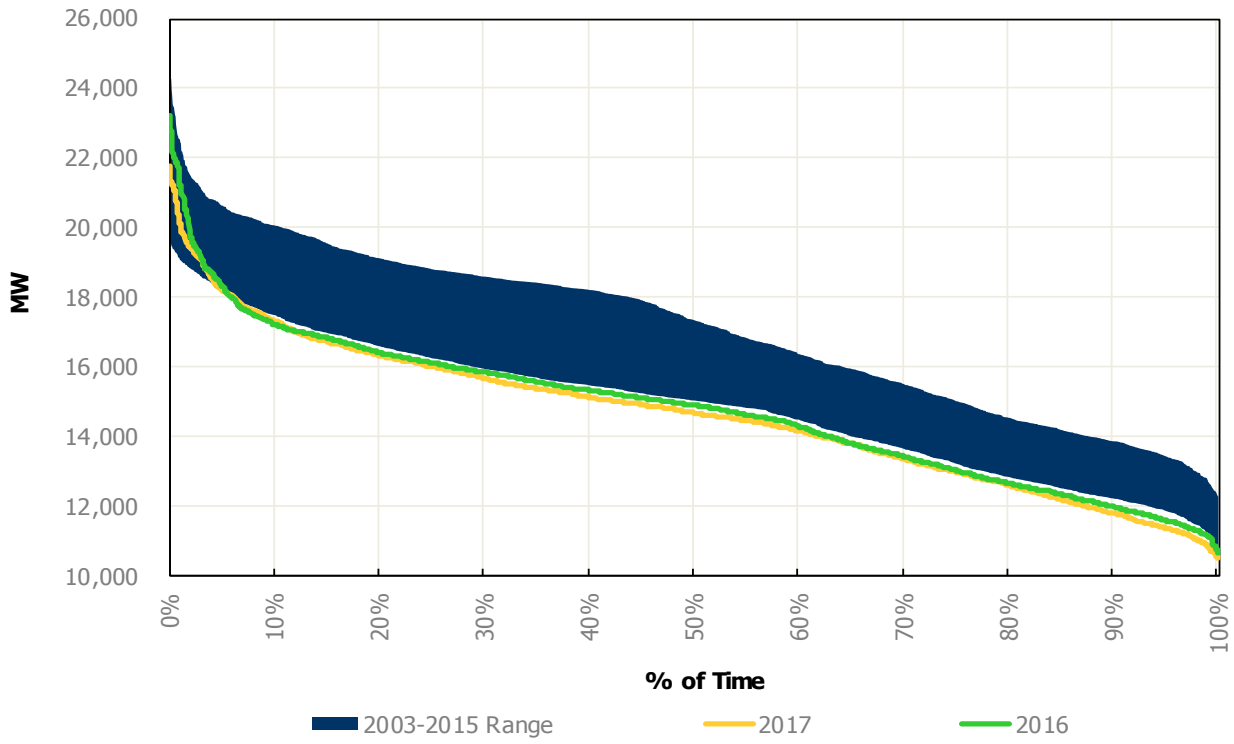
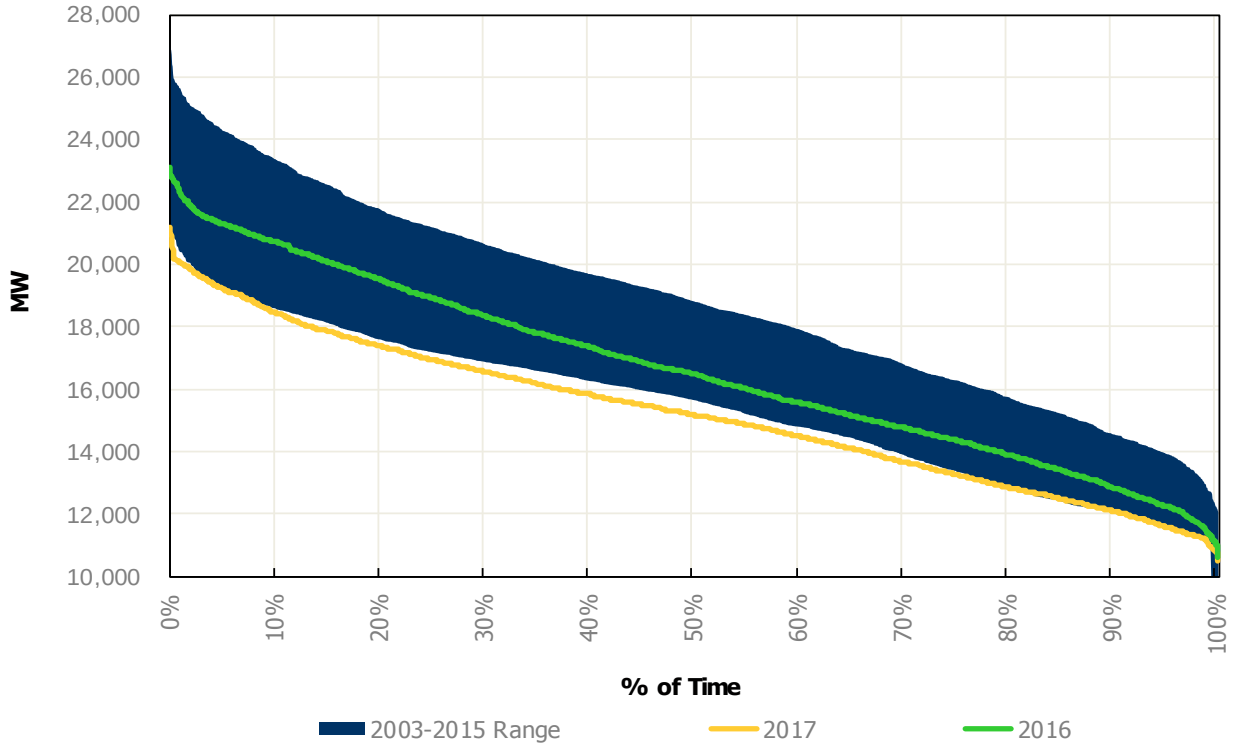


Figure 3.19: Summer Load Duration Curve



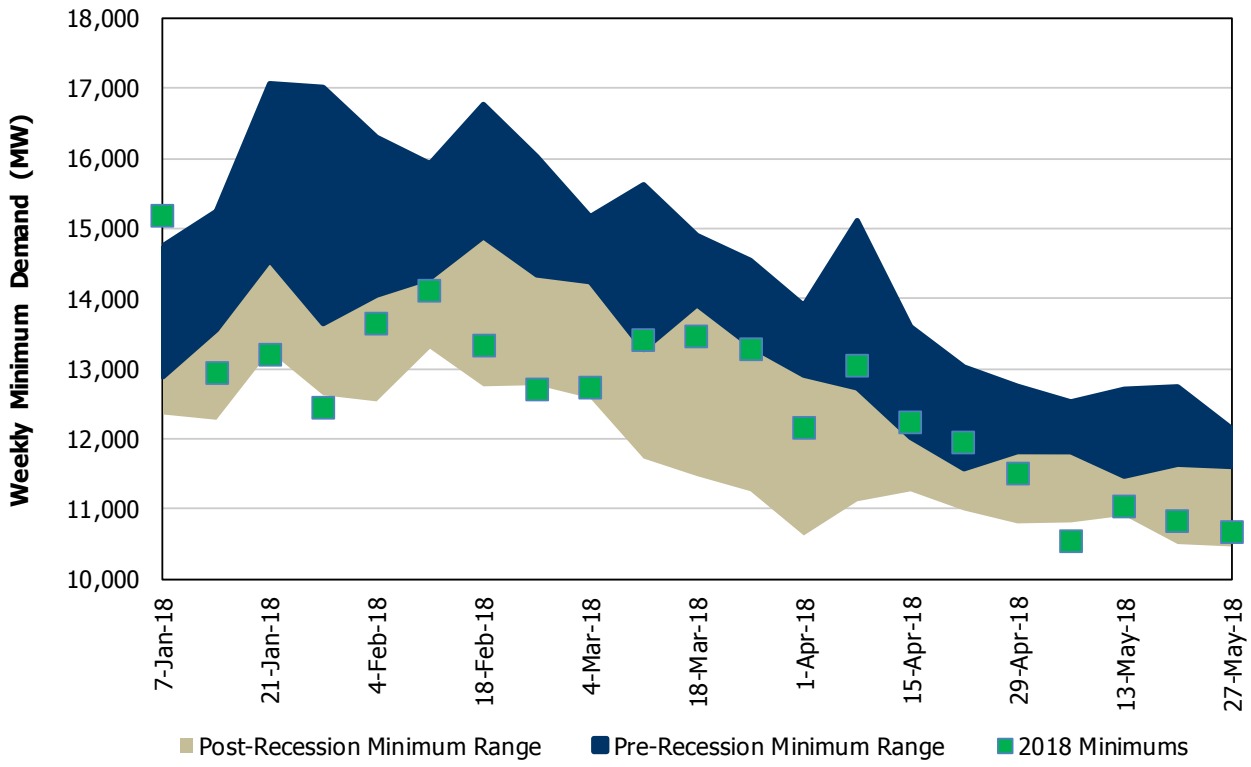
3.5 Historical Minimum Demand

Like peak demands, minimum demands are driven by weather, calendar and economic effects. The importance of the drivers varies by season. The winter, spring and fall have the potential for heating load, whereas the summer period has the potential for cooling loads. Minimums continue to establish new lows in the post-recession era due to lower industrial loads, conservation and increased embedded generation. In the case of minimums that occur during the predawn hours, it is embedded wind that 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 May 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 to 2016 time frame. The squares represent the weekly minimums for the past five months. The weekly minimums occur during the early morning hours of the weekend, when the level of economic activity is lowest.

The minimums of the past five months reflect the episodes of mild weather and low levels of demand in 2018. In 2017, 23 weeks had minimums that ended up being all-time lows for the week. With overall demand being higher thus far in 2018, only twice has the weekly minimum establish a new low. Once was in the fourth week of January during a mild spell and the second was in the first week of May when XX. Minimums move in conjunction with overall demand.

Figure 3.20: Weekly Minimum Demands



- End of Section -

4.0 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 web site at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2018jun.pdf.

The form and structure of the model have been modified to enhance and strengthen the explanatory powers of the economic drivers, conservation and embedded generation. 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 pretty 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.

As discussed earlier in this report, the economy has strong fundamentals - low interest rates, a low exchange rate and strong U.S. growth. This should benefit both Canada and Ontario over the forecast horizon. However, there exists significant downside risk in terms of trade disruptions.

Ontario's economy has seen robust growth throughout 2017, but that didn't translate into increased electricity demand. Most of the sectors that have driven growth have not been electricity-intense sectors. Construction, retail, financial services and the technology sector have helped propel Ontario's economic growth but do not translate into increased electricity demand. So far in 2018,

The energy-intense manufacturing sectors of Ontario's economy tend to be export-oriented and exports are down on a year–to-date basis. Though certain sectors were up – metals and iron and steel, others have tailed off – consumer goods and motor vehicles.

Ontario generated 124,000 jobs in 2017, an increase of 1.8 percent over 2016. That growth was broad based – full time employment is up 1.8 percent and part time is up 1.7 percent. Manufacturing is up 2.0 percent and service sector employment is up 2.1 percent. The resource sector was the one sector that saw a slight decline. These are encouraging numbers as they indicate sustained economic growth.

Looking forward over the forecast horizon the stable economic environment is expected continue with increased opportunity for export-oriented businesses and continued strong U.S. growth. Electricity demand is also expected to be buoyed by increased demand from the greenhouse sector in 2018-19.

There are a significant number of downside risks to the Ontario economic outlook. In particular, Ontario would be disproportionately impacted, more so than any province, should NAFTA be terminated. Although CETA and the TPP would present additional export opportunities, they would take time to grow. Those expanded markets will not shield the Ontario economy from any US/Canada trade issues in the near term.

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	1.9	79.6	13.3	1.169	1.65
2003	6,213	3.0	80.9	1.7	1.198	2.49
2004	6,314	1.6	79.9	-1.3	1.219	1.81
2005	6,381	1.1	73.2	-8.4	1.236	1.39
2006	6,452	1.1	67.8	-7.4	1.253	1.35
2007	6,545	1.4	62.8	-7.4	1.271	1.41
2008	6,610	1.0	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	1.60
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 (f)	7,224	1.3	73.2	-2.7	1.434	1.36
2019 (f)	7,290	0.9	69.7	-4.8	1.450	1.11

The IESO has highlighted the shifting patterns in Ontario's employment as a measuring stick for sustained growth. Since the recession, growth has been sector- or region-specific and not broad-based. To generalize, much of the growth was centered in the service sector and in the GTA. However, 2017 showed a marked departure in the labour markets as the following graphs show.

Figure 4.1 shows the year-over-year change in employment for Ontario, the Toronto zone and all other zones combined. Broad-based growth would mean that both Toronto and the other zones would be enjoying similar job creation. For the period following the recession, Ontario's economy experienced fairly broad-based growth over the 2010-2011 timeframe. Over the 2012-2016 time frame growth has been an "either/or" experience with either the GTA or the rest of the province dominating. This year job growth has been more balanced between the two sub-provincial areas.

Figure 4.2 shows the year-over-year changes in employment broken down into services, manufacturing and other goods (mining, construction, agriculture, forestry, etc.). As with the zonal growth, a more broad-based and sustainable growth pattern would have growth across all of the sub-sectors. Throughout 2017 employment growth is showing signs of being across all sectors.

These graphs point to a more broad-based employment pattern, across regions and sectors. This is indicative of a more sustained economic expansion. Together with strong underlying economic fundamentals of low inflation, low interest rates and a competitive dollar, this will help the Ontario economy grow over the forecast horizon.

Figure 4.1: Zonal Employment Growth

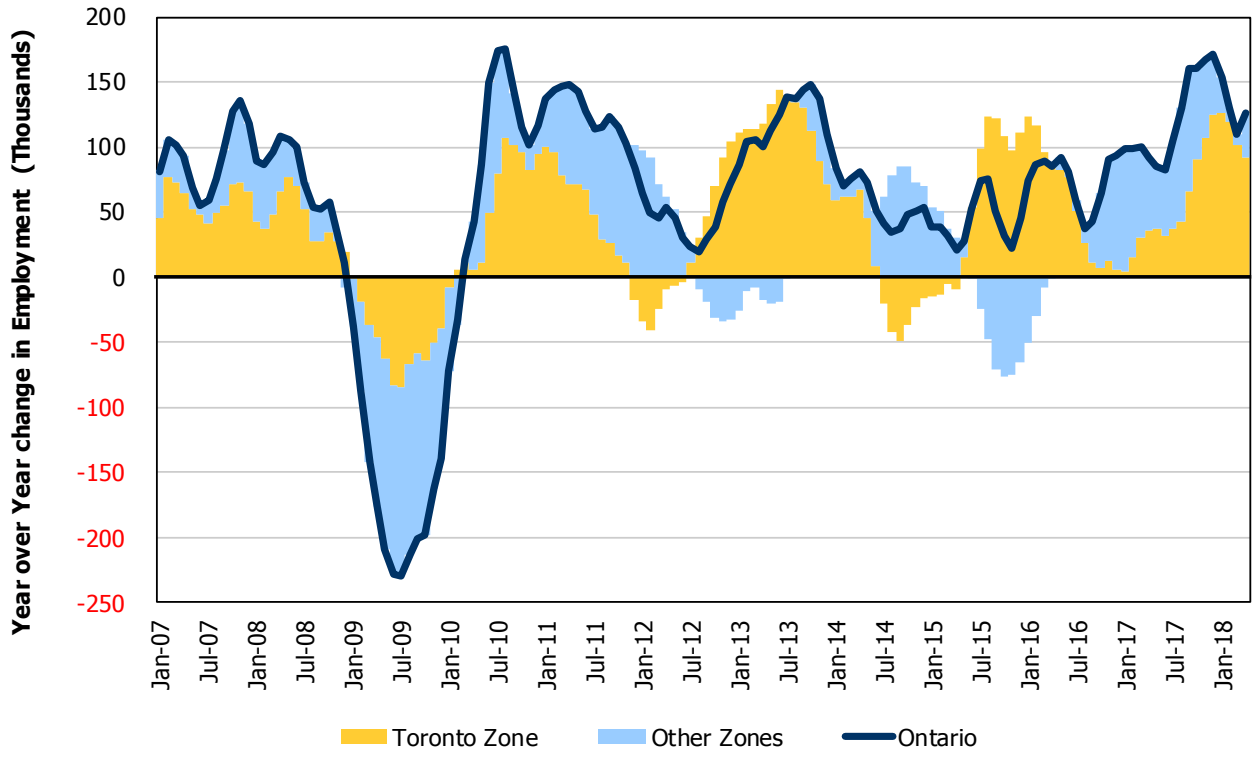
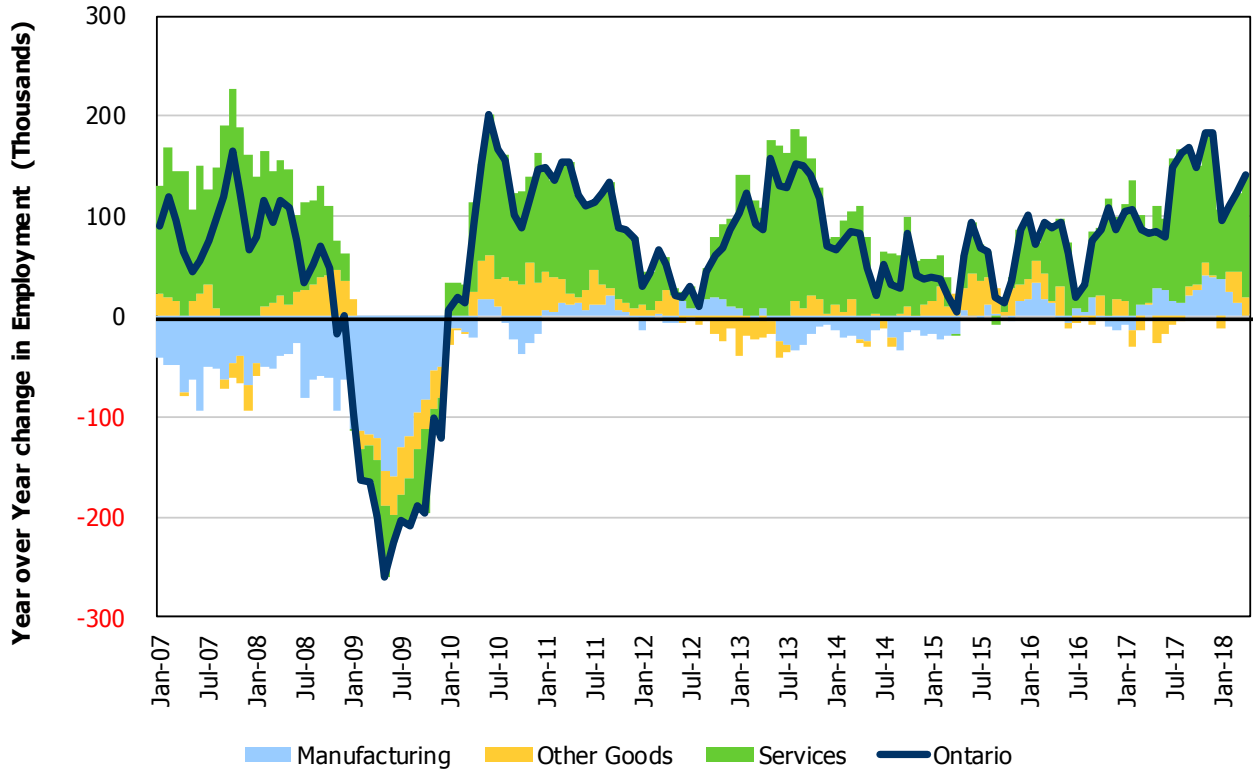


Figure 4.2: Composition of Ontario's Employment Growth



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, a variety of inputs are required. Therefore, the IESO produces demand forecasts based on a number of different weather scenarios. The most commonly utilized scenarios are 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 from each January from 1980 to 2010 would be the first value for the normal January. The median value of the second highest weather factor from 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 a full range of peak demands that can occur under various weather conditions with varying probability of occurrence.

The Extreme weather scenario is valuable for studying situations where the system is under duress. Although the Extreme weather scenario is 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 18-Month 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

There are a number of initiatives and policies that have an impact on electricity demand. They can be grouped into two categories: demand measures and load modifiers. The rationale for the two categories is how they are treated with respect to the demand forecast. Demand measures are not incorporated into the demand forecast whereas the load modifiers are. In essence, demand measures are controllable while load modifiers are not. Demand measures include dispatchable loads and demand response programs. 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 the correct accounting of demand measures, they must be treated equitably on both sides of the ledger. Therefore, 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 the various demand response programs. Demand measures have no impact on the demand forecast.

Load Modifiers -- Conservation

Conservation includes energy-efficiency programs, codes and standards and fuel switching. Projected conservation numbers are based on existing and future 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 with the result of 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. As both are relatively new, information continues to be 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 overall impact will be to shift load within the day or week. 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 with an average monthly peak demand greater than 500 kW and less than 1 MW who are in the manufacturing and greenhouse sectors. As well, those 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 as both the number of participants have increased and the participants have improved their ability to identify and react to the peaks. First-year (2010) reductions were estimated at 200 MW, growing to an estimated 1,300 MW for the five peak days in 2016. The estimates for the ICI impacts on the 2017-18 peaks are 1,400 MW. Both TOU and ICI impacts are incorporated into the demand forecast.

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. All output provided by embedded generation is an offset to grid-supplied electricity. Therefore, 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. As the graph shows, the vast majority of the embedded generation is solar. Due to its large share, solar output is treated differently than the other fuel types. The impact of solar generation is generated by using engineering models that use location, cloud cover and temperature to estimate solar production. The remaining embedded generation fuel types' output is produced using average production profiles based on history. The total embedded generation output is then incorporated into the demand forecast. Table 4.2 has a summary of the estimated embedded capacity by fuel type as of June for the history and the forecast period. A more detailed table is included in the 18-Month Outlook Tables.

Figure 4.3: Projected Embedded Generation Capacity

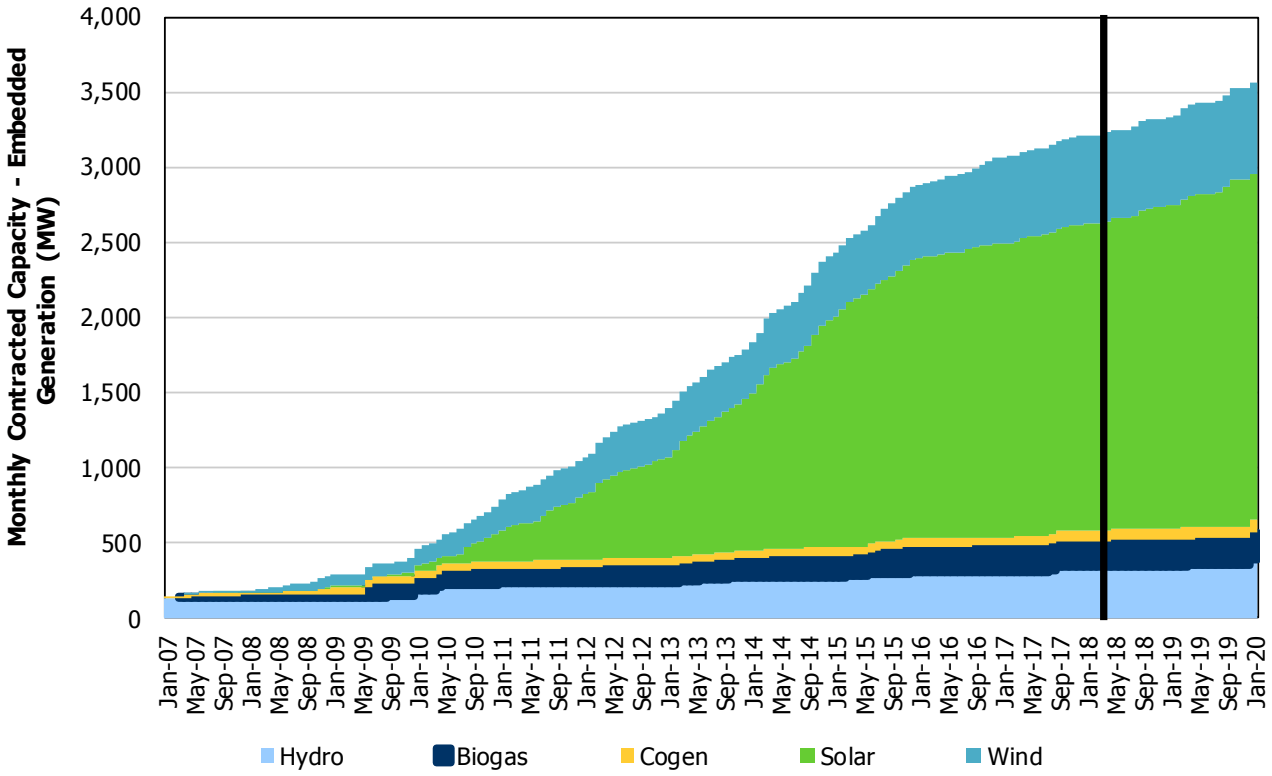


Table 4.2: Embedded Capacity

Month	Estimate of Contracted Embedded Generation Capacity (MW)					
	Biogas	Cogeneration	Solar	Hydro	Wind	Total
Jun-07	14	18	0	132	7	171
Jun-08	20	25	0	134	38	218
Jun-09	61	49	10	139	74	335
Jun-10	94	49	54	220	160	576
Jun-11	108	49	265	226	241	890
Jun-12	114	49	580	234	298	1,276
Jun-13	125	49	849	250	335	1,608
Jun-14	137	55	1,240	271	373	2,077
Jun-15	153	55	1,695	286	430	2,619
Jun-16	176	60	1,898	298	515	2,947
Jun-17	176	67	1,997	306	580	3,126
Jun-18	178	73	2,065	345	591	3,251
Jun-19	181	76	2,214	352	609	3,432

Over the course of the 18-month forecast, the amount of embedded solar installed capacity will range from over 2,000 MW to just over 2,200 MW. The impact of embedded solar on demand will vary over the course of the year and the time of day, due to the amount of sunlight available. Note that, as discussed in section 3.3, embedded solar is having the impact of pushing summer peaks later in the day. As peaks move later in the day, the result is a reduction in the solar capacity contribution. Therefore solar capacity contribution during peak demand has decreased and will continue to decline.

- End of Document -

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