Ontario Demand Forecast

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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 2019 to June 2020 and supersedes the previous forecast released in September 2018.

Economic Outlook

The Ontario economy continued to experience growth throughout 2018 due to the strong fundamentals of low interest rates, strong U.S. growth and a competitive dollar. However, the current economic cycle of sustained growth is starting to show signs of deterioration. Interest rates have begun to increase with the expectation of further increases. Higher rates will act as a brake on the economy. Throughout 2018, employment growth has slowed, the housing market has cooled and on-going trade disruptions have cast a pall on the global economy. The economy is expected to see continued growth over the forecast horizon, but at a lower rate.

Looking forward there is significantly more downside risk than upside risk. The current growth cycle is predicted to l end and however the timing of the growth period is uncertain. . As consumption is the largest portion of the economy, consumer confidence is an important factor in shaping the trajectory of the growth. Against the chaos of 2018 Canadian consumer confidence has been equally volatile. Confidence reached a two year low over the summer of 2018 amidst trade frictions between the U.S. and Canada. Since then, confidence has rebounded with the updated United States-Mexico-Canada Agreement trade deal. As changeable as confidence is, it will play a key role in determining the growth over the next year and a half. Continued employment growth will fuel spending and, in turn, growth

Alongside these shorter term cycles, the underlying longer term trend for the Ontario economy is a transition from goods to services. The service sector will continue to account for a larger share of the economy while manufacturing's sector continues to decline. This has implications for electricity demand as the electrical intensity of these two main sectors – service and manufacturing – is significantly different. Service sector growth has a much smaller impact on electricity demand than comparable growth in manufacturing.

Over the forecast horizon Ontario will see increased electricity demand from certain sectors of the economy. Mining and the burgeoning greenhouse sector are both sources of increased electricity demand. The greenhouse sector is expanding due to both the production of cannabis, as well as the increased production of fruits and vegetables. Recent announcements in the automotive and parts supplier industries are indicating reduced signs of growth in the province beyond 2019.

There remain significant risks to the forecast. Debt issues and geo-political events could disrupt the trajectory of Ontario's economy and undermine consumer confidence. Despite the USMCA trade deal, Canada is still subject to U.S. steel and aluminum tariffs which will have an increasingly negative impact if they persist. Finally, as noted earlier, the current growth cycle is reaching ten years which is long by historical standards.

Actual Weather and Demand

Since the last Ontario Demand Forecast document was published actual demand figures for the six months of June through November have been recorded. They show 2018 has been a very similar to 2016 in terms of both energy and peak demand. In fact, it highlights how 2017 was an anomaly. The decline in 2017 spanned all industrial sectors and all distributors and had no apparent root cause at this time.

For the past six months, distributor loads have increased by 6.8 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 3.3 percent. In comparing to 2016 however, those distributor loads are relatively flat with an actual increase of 1.4 percent and a weather corrected decline of 0.4 percent.

Wholesale customers' consumption increased by 2.5 percent against 2017 but showed a 0.2 percent decline against the same six months in 2016. The results in 2018 were a reversal of 2017, as iron and steel consumption declined while the rest of the other major sectors showed improvement over 2017. For the same six month period in 2017 iron and steel was the lone bright spot.

Peak demand for the summer of 2018 occurred in July. The September peak was also very high, and could be deemed the annual peak depending on the measurement used. The system had peaked in September the previous two years. There was a heat wave in September 2018 and the peak demand was 23,131 MW just below the July demand peak of 23,374 MW on July 5. At this point in time, it also represents the annual peak. After correcting for weather, the July peak is slightly lower at 22,572 MW. The September weather corrected peak demand was 19,784 MW. The peak values were impacts by the Industrial Conservation Initiative (ICI) which increased downward pressure on the peak.

The weather over the course of the summer was warmer than normal. July and August both experienced periods of sustained heat that drove higher consumption and higher peak demands.

The fall was also colder than normal. Although September was warmer than normal, both October and November were not. Both the September and October peak occurred during a sustained warm period, while November's peak occurred on the coldest day of the month.

Overall, embedded generation for the summer and fall was 5.5 percent lower than the same period a year ago. The decline was due to lower wind and hydro-electric 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 peaks are expected to continue their 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 significant increase in 2018 which would be more in line with the trend since the 2009 recession. At this point, it is clean that 2017's decline was more the anomaly than 2018's growth. Despite the growth in 2018, the weather corrected energy values will be lower than those for 2016. The forecast is expected to continue exhibit small declines in overall consumption as gains in energy efficiency, prices and economic change trump increased demand from economic and demographic growth.

Table 1: Peak Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2018-19	21,506	22,434
Summer 2019	21,958	24,384
Winter 2019-20	21,203	22,084

Table 2: Energy Demand Forecast

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 (Forecast)	135.5	2.4%
2019 (Forecast)	134.8	-0.5%
2020 (Forecast)	134.3	-0.4%

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1. 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 January 2019 to June 2020. It supersedes the previous forecast released in September 2018 and the previous Ontario Demand Forecast document released in June 2018.

1.2 Demand Forecast Document

This document provides a forecast of electricity demand for Ontario, based on the stated assumptions and using the methodology described the Methodology to Perform the Reliability Outlook. 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 2018. 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 Outlook Tables 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.

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 the historical weekly energy and peak demand along with the projected forecast.

Compared to the previous forecast, the weekly peaks and energy demand are lower throughout the forecast.

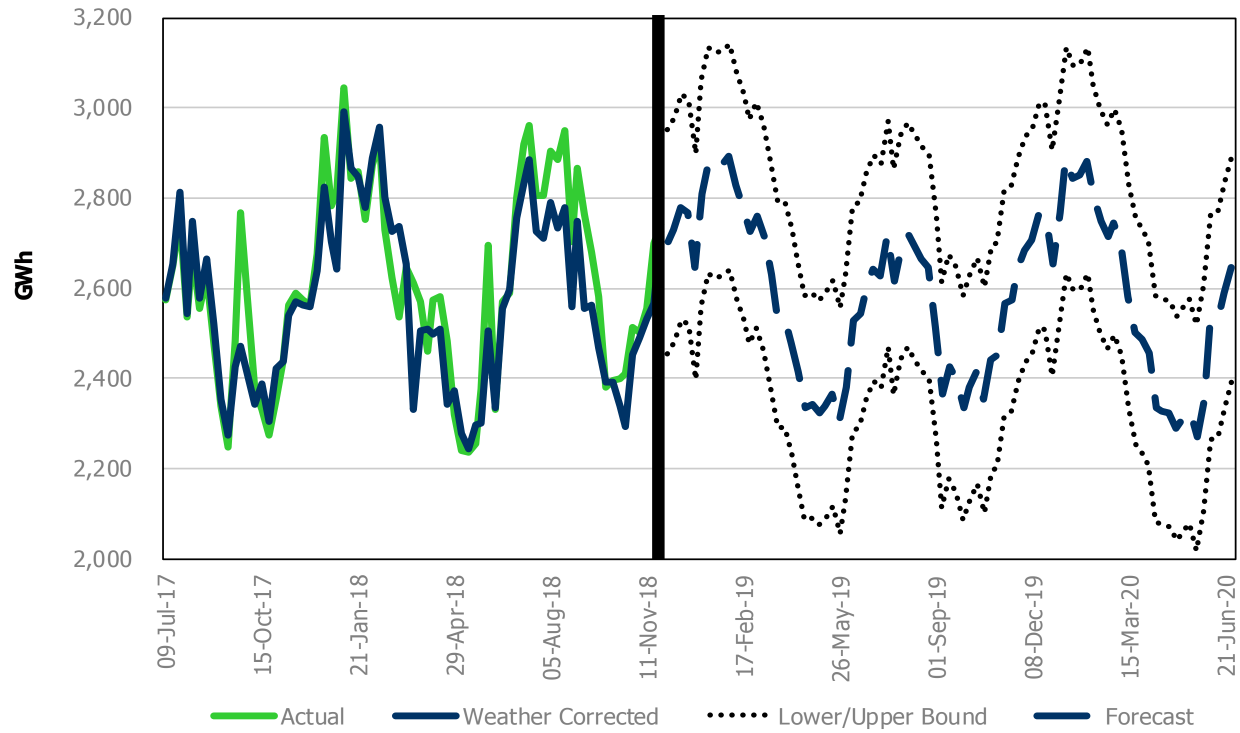

Figure 2-1 | Weekly Energy Demand - History and Forecast

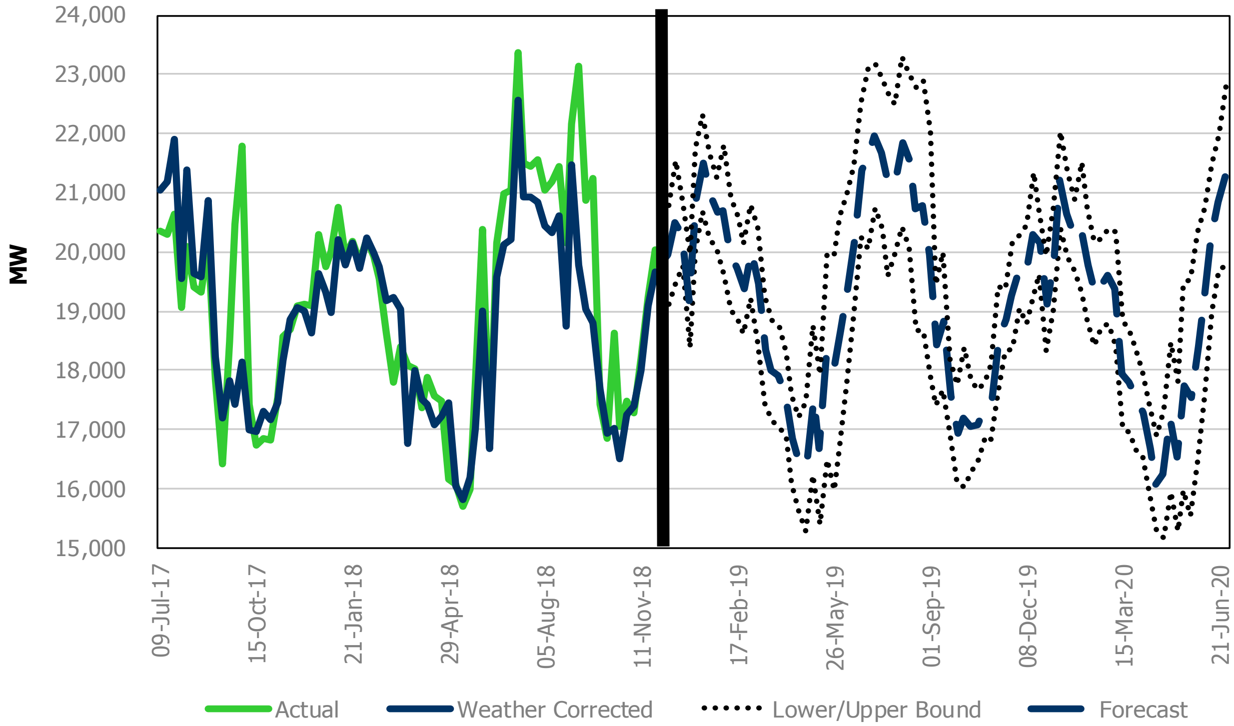

Figure 2-2 | Weekly Peak Demand – History and Forecast

Table 2-1 | Weekly Energy and Peak Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
06-Jan-19	20,545	21,858	570	2,617
13-Jan-19	21,506	22,434	547	2,883
20-Jan-19	20,941	21,572	483	2,872
27-Jan-19	20,658	21,755	404	2,878
03-Feb-19	20,707	21,899	734	2,891
10-Feb-19	19,972	21,491	635	2,827
17-Feb-19	19,722	21,202	581	2,780
24-Feb-19	19,378	21,202	501	2,725
03-Mar-19	20,008	21,262	531	2,761
10-Mar-19	19,457	20,376	649	2,713
17-Mar-19	18,342	19,142	611	2,629
24-Mar-19	17,999	18,745	569	2,542
31-Mar-19	17,898	18,926	567	2,541
07-Apr-19	17,605	18,198	471	2,479
14-Apr-19	16,836	17,835	496	2,414
21-Apr-19	16,419	16,713	531	2,335
28-Apr-19	16,375	16,527	721	2,340
05-May-19	17,499	19,926	849	2,322
12-May-19	16,669	19,425	845	2,339
19-May-19	18,240	21,536	1,175	2,365
26-May-19	17,976	21,702	1,330	2,305
02-Jun-19	18,660	21,235	1,292	2,380
09-Jun-19	19,378	23,698	1,055	2,530
16-Jun-19	20,219	23,681	835	2,542
23-Jun-19	21,382	23,949	754	2,609
30-Jun-19	21,570	23,549	1,016	2,643
07-Jul-19	21,958	24,373	814	2,626
14-Jul-19	21,660	23,359	838	2,719
21-Jul-19	21,140	23,371	1,035	2,614
28-Jul-19	21,224	24,031	841	2,691
04-Aug-19	21,848	24,384	958	2,718
11-Aug-19	21,544	24,237	985	2,688
18-Aug-19	20,725	23,833	1,362	2,664
25-Aug-19	20,782	22,837	1,413	2,646

Continued on next page

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
01-Sep-19	19,964	22,472	1,370	2,513
08-Sep-19	18,428	23,311	680	2,364
15-Sep-19	18,826	20,890	781	2,425
22-Sep-19	17,555	19,369	420	2,396
29-Sep-19	16,925	18,208	554	2,334
06-Oct-19	17,203	17,253	786	2,381
13-Oct-19	17,061	17,311	507	2,415
20-Oct-19	17,083	17,637	392	2,352
27-Oct-19	17,359	17,929	318	2,442
03-Nov-19	17,469	18,328	416	2,452
10-Nov-19	18,531	19,302	601	2,565
17-Nov-19	18,845	19,666	342	2,575
24-Nov-19	19,269	19,983	607	2,641
01-Dec-19	19,664	20,740	409	2,685
08-Dec-19	19,617	20,915	555	2,707
15-Dec-19	20,303	21,305	690	2,763
22-Dec-19	20,150	21,240	362	2,758
29-Dec-19	19,130	19,266	528	2,655
05-Jan-20	19,882	20,962	570	2,767
12-Jan-20	21,203	22,084	547	2,883
19-Jan-20	20,628	20,982	483	2,843
26-Jan-20	20,287	21,504	404	2,850
02-Feb-20	20,419	21,693	734	2,882
09-Feb-20	19,787	21,427	635	2,801
16-Feb-20	19,287	20,812	581	2,749
23-Feb-20	19,471	21,190	501	2,713
01-Mar-20	19,591	21,017	531	2,746
08-Mar-20	19,378	20,327	649	2,699
15-Mar-20	17,934	18,470	611	2,580
22-Mar-20	17,788	18,341	569	2,503
29-Mar-20	17,524	18,385	567	2,486
05-Apr-20	17,276	17,918	471	2,455
12-Apr-20	16,662	17,296	496	2,333

Continued on next page

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
19-Apr-20	16,081	16,147	531	2,325
26-Apr-20	16,247	16,709	721	2,322
03-May-20	17,206	19,678	849	2,289
10-May-20	16,541	19,386	845	2,311
17-May-20	17,725	21,229	1,175	2,326
24-May-20	17,536	21,512	1,330	2,269
31-May-20	18,391	21,010	1,292	2,354
07-Jun-20	19,155	23,608	1,055	2,515
14-Jun-20	20,248	23,880	835	2,519
21-Jun-20	20,834	23,496	754	2,587
28-Jun-20	21,279	23,813	1,016	2,645
05-Jul-20	19,394	22,118	814	2,598

3. Historic 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. Starting in the spring of 2018, demand has seen a marked increase compared to the previous year. This increase is less about 2018 than how 2017 was such an off year.

The summer of 2018 was hotter than normal. The fall of 2018 started hotter than normal but ended up being much colder than normal overall.

The actual and weather-corrected summer peak occurred in July (23,374 MW and 22,572 MW weather-corrected). Similar to the previous two years, which saw the summer peaks occur in September, 2018 also had a significant peak in September (23,131 MW).

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

June

June's weather was slightly above normal on average as the month started out mild before heating up into the Canada Day long weekend. Temperatures later in the month were significantly above normal, but peaks were blunted by the two hottest days occurring on weekends. Figure 3.1 presents the ranked range of temperatures for the month, from warmest to coldest. The values for the month were consistently normal based on the history (1970 to present).

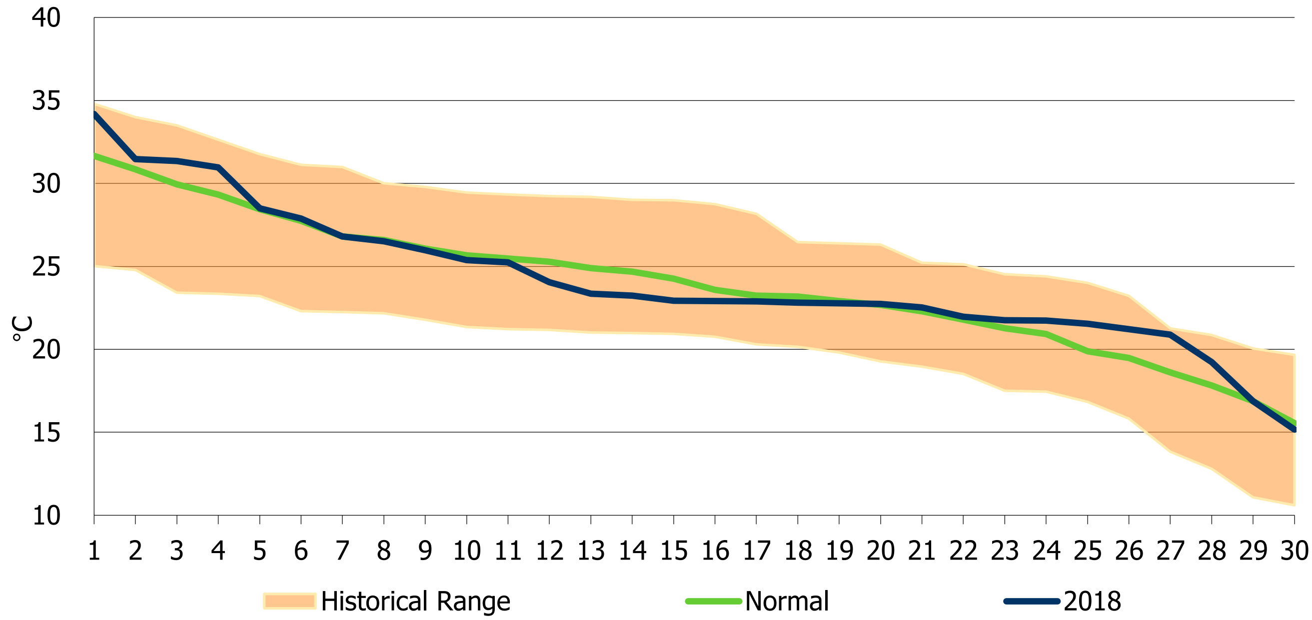

Figure 3-1 | Daily Temperature - June

- The June peak occurred on Monday June 18, the fourth hottest day of the month following a very hot weekend. While consistent with the numbers recorded over the last several years, at 21,369 MW this year's June peak was unusual, as it occurred early in the day as a storm rolled across the province, bringing a cold front and breaking the heat wave. The afternoon high was 31°C (in Toronto), but by that time the weather had already turned cooler. Since the peak occurred earlier in the day, it was subject to significantly greater downward pressure both from embedded solar and ICI customers actively reducing their load at the time of the peak.
- The weather-corrected peak was 20,502 MW, which is consistent with June weather-corrected peaks from 2015 and 2017.
- Energy demand for the month was 10.9 TWh (10.9 TWh weather corrected), which is an increase over June 2017.
- The minimum demand for the month was 10,698 MW which is in line with recent June values since the last recession. The minimum occurred in the early hours of Sunday June 10.
- Embedded generation for the month was 601 GWh, an increase of 4.2 percent compared to the previous June. Solar output accounted for the increase as all other fuel types were down compared to June 2017.
- Wholesale customers' consumption rose 2.3 percent over June 2017 and represented the largest monthly gain in over two years. Big increases in the mining sector (14.8%) and petroleum (7.0%), more than offset declines in iron and steel (-5.2%) and the automotive sector (-1.7%).

July

The weather for July was consistently warmer than normal across the month. The month started on a heat wave over the Canada Day weekend. Figure 3.2 shows how the temperature for July 2018 stacked up against history.

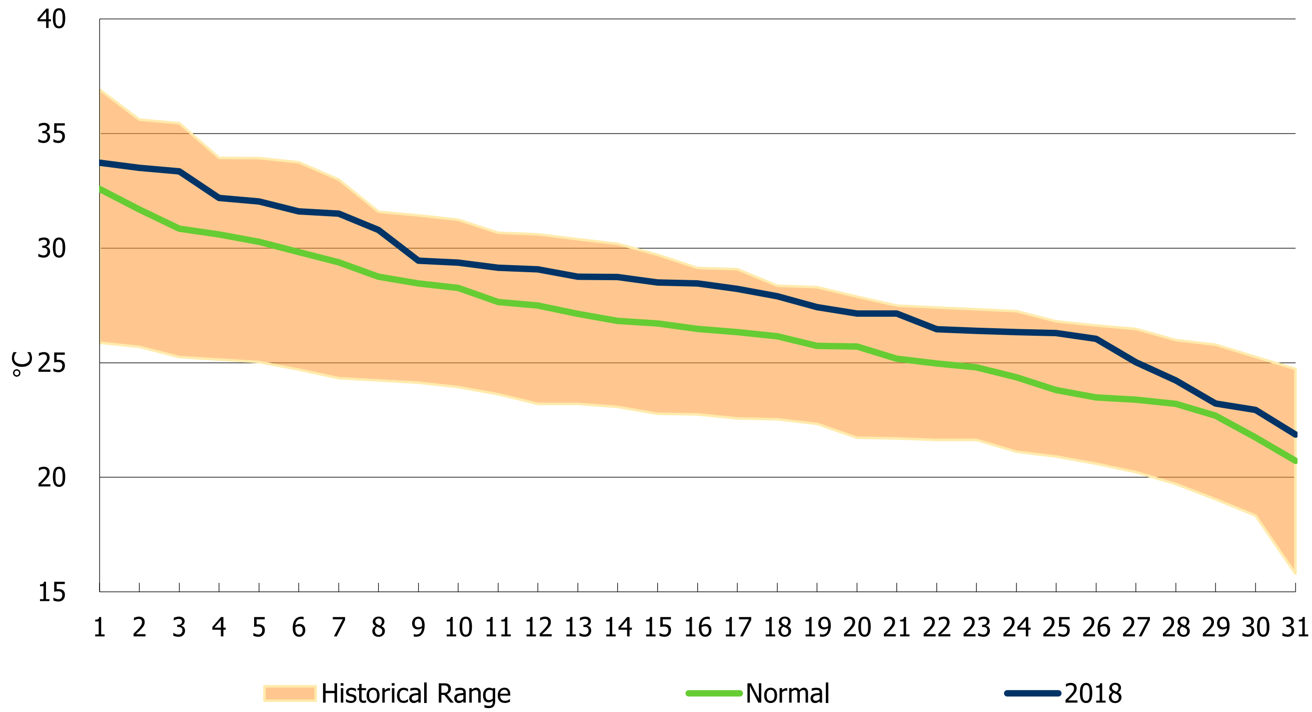

Figure 3-2 | Daily Temperature - July

- While the hottest days of the month occurred during the holiday weekend, the peak of 23,046 MW (22,244 MW weather corrected) was recorded on July 5, which was the fourth hottest day of the month with the humidex topping 40°C. ICI actions reduced demand on the peak day. Since July was above normal ICI actions occurred on seven days throughout the month.
- Energy demand for the month was 12.7 TWh (12.3 TWh weather corrected). Both of these values are the highest since July 2013.
- The minimum for the month was 11,413 MW and occurred in the early morning hours of Sunday July 8, after the heat wave had ended.
- Embedded generation for the month topped 516 GWh, which represents an 11.2 percent decrease compared to the previous July. Solar output was up, but all other fuel types were down.
- After four months of positive growth, wholesale customers’ load had a reversal in July dropping by 1.2 percent compared to the previous July. The reductions were fairly broad based.

August

The weather for August was hotter than normal, with average temperatures for the month making it the second hottest August in forty years. Peak temperatures, while above normal, were not record highs. Figure 3.3 shows the August 2018 temperature relative to history.

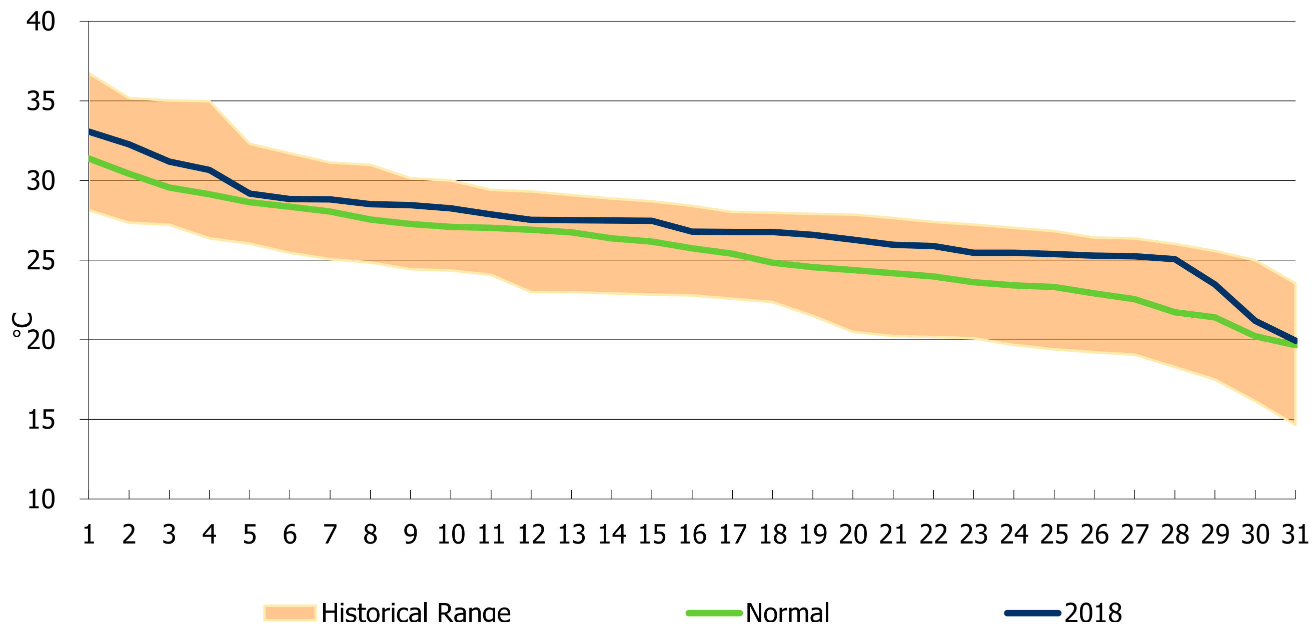

Figure 3-3 | Daily Temperature - August

- The August peak was recorded on the third hottest day of the month, as the two hottest days occurred over the Civic Holiday long weekend. Peak demand for the month was 21,990 MW (21,274 MW weather corrected). ICI actions occurred on this day, as well as on two others in the month.
- Energy demand for the month was 12.7 TWh (12.2 TWh weather corrected). Both are increases over the previous August.
- While minimums usually occur on weekends or holidays, the lowest demand in August was 11,966 MW and occurred during the early morning hours of Thursday, August 23.The 23rd was one of the mildest days of the month which led to lower air conditioning use and a monthly minimum.
- Embedded generation for the month topped 530 GWh, which represents a 5.0 percent decrease compared to the previous August. Solar (14%) and wind (6%) output was up, but all other fuel types were down.
- After a step back in July, wholesale customers' load grew by 2.3 percent compared to the previous August. Other than mining, all major sectors showed growth over the previous August.

September

September's weather was above normal on average as the month started out hot and humid leading into the Labour Day weekend. Temperatures later in the month tailed off and returned to normal. Figure 3.4 shows the September 2018 temperatures against the historical range.

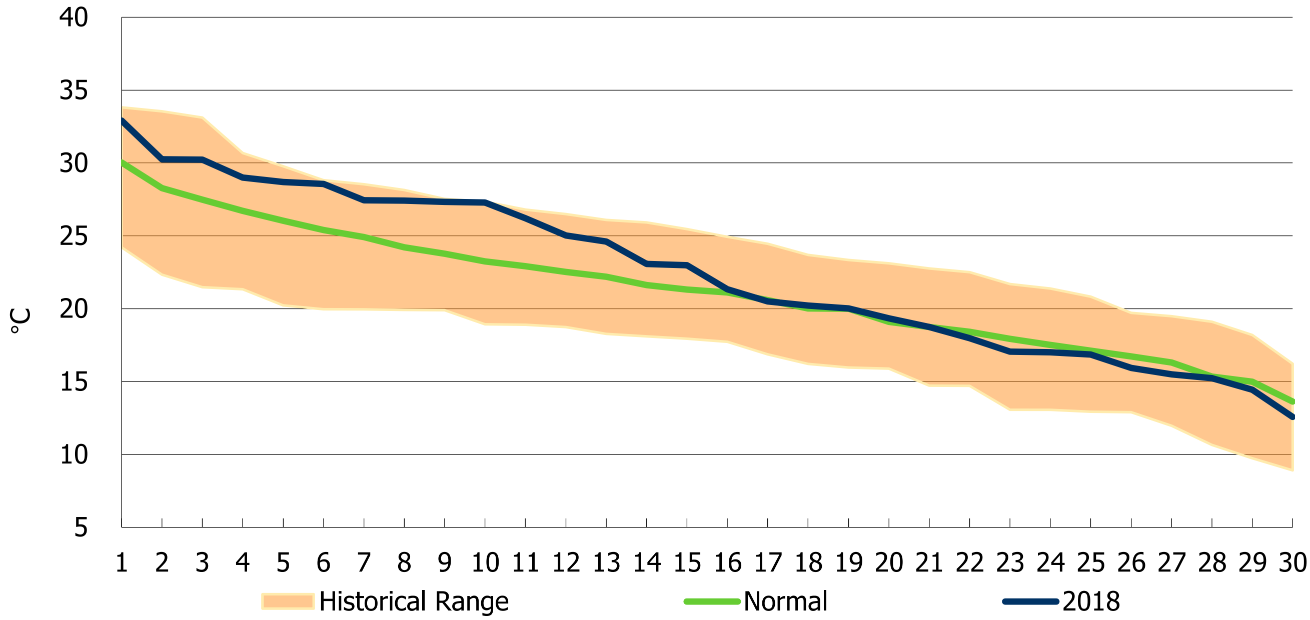

Figure 3-4 | Daily Temperature - September

- The September peak occurred on Wednesday September 5 which was the hottest day of the month with temperatures peaking at 33.9°C (Toronto). The peak (23,131 MW) was very similar to the 2016 September peak of 23,213 MW on a daily high of 34.5°C. The peak was subject to downward pressure from both embedded solar and ICI customers actively reducing their load at the time of the peak.
- The weather-corrected peak (19,784 MW) was fairly consistent with September 2016's 20,000 MW weather corrected peak.
- Energy demand for the month was 11.2 TWh (10.7 TWh weather corrected), which is an increase over the previous September but very similar to September 2016.
- The minimum demand for the month (10,809 MW) is an increase over 2017 but in line with September values since the last recession. The minimum occurred in the early hours of Sunday September 9.
- Embedded generation for the month was 481 GWh, a decrease of 0.2 percent compared to the previous September. Solar output was down 2.1 percent and wind output was down 4.9 percent compared to the previous September. Non-contracted generation accounted for was up, offsetting the decline in renewable output.

- Wholesale customers' consumption rose 11.2 percent over September 2017 and represented the largest monthly gain since October 2010. Once again, much of the explanation lies with the dismal 2017 number than the growth in 2018 as wholesale customers saw their load drop by 10.6 percent compared to September 2016. All major sectors saw significant year over year increases.

October

The weather for October was consistently cooler than normal with the exception of the warm week and a half to start the month. October's peak was a warm weather peak for the second year in a row. Figure 3.5 illustrates the temperatures of October 2018 against the historical range.

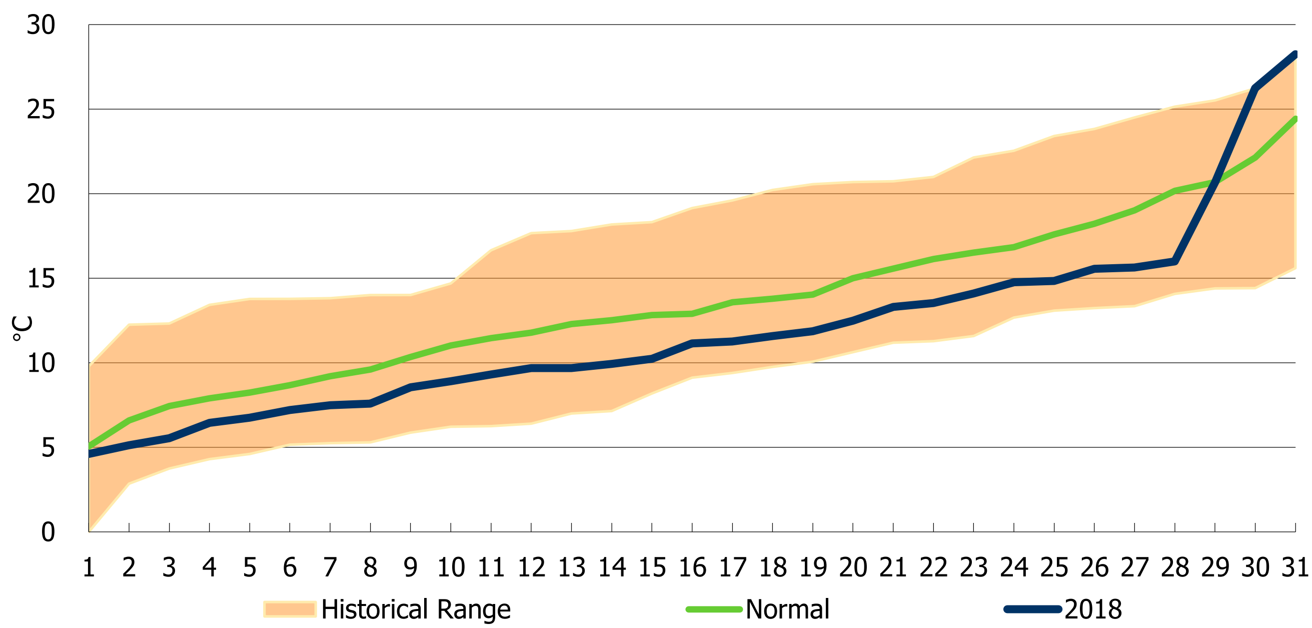

Figure 3-5 | Daily Temperature - October

- The peak occurred on the hottest day of the month when temperatures topped 28°C (Toronto). The peak demand was 18,640 MW (18,036 MW weather corrected) on the Tuesday after Thanksgiving (October 9). The peak was an increase over 2017, but generally in line with the figures since the recession.

- Energy demand for the month was 10.8 TWh (10.6 TWh weather corrected). Both of these values are consistent with the numbers over the past three years.

- The minimum for the month was 11,052 MW and occurred in the early morning hours of Thanksgiving October 8.

- Embedded generation for the month topped 489 GWh, which represents an 8.2 percent decrease compared to the previous October. Wind and bio-fuel output was up over the previous year, all other fuels showed a decline.

- Wholesale customers' load increased by 0.9 percent compared to the previous October. Growth was broad based with the exception of Iron and Steel which took a step back this month.

November

November was much cooler than normal being the third coldest November over the past fifty years. Figure 3.6 shows how the temperature for November 2018 stacked up against history.

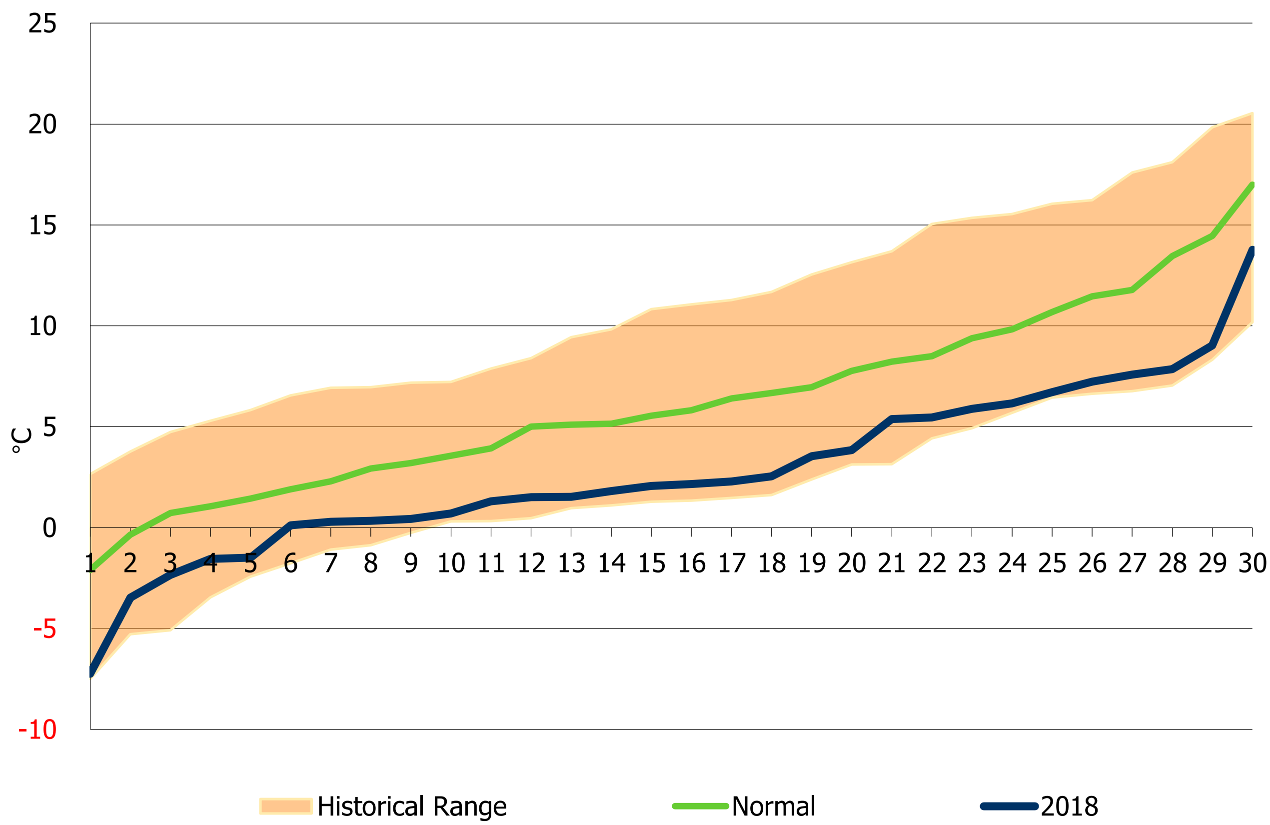

Figure 3-6 | Daily Temperature - November

- The actual peak for the month was 20,048 MW occurring on Thursday, November 22. It was the coldest day of the month with afternoon highs of -6.6°C (Toronto). The weather-corrected value was virtually the same at 19,243 MW which is consistent with the values experienced since the recession.

- Energy demand for the month was 11.4 TWh (11.0 TWh weather-corrected). Both the actual and weather-corrected values are a slight increase over the previous three Novembers.

- Minimum demand of 12,050 MW occurred Wednesday, November 7 at 4 a.m. This is very unusual as most minimums occur on weekends or holidays. This mid-week minimum was a product of the warmest temperatures of the month. Colder temperatures on the weekends drove overnight heating load pushing the minimum to a weekday.

- Embedded generation was 435 GWh for the month, which represents a decrease of 13 percent compared to the previous November. Decreases in wind (8 percent) and solar (19 percent) out-weighed the increase in hydro output (15 percent).
- Wholesale customers' consumption increased 0.4 percent compared to the previous November. All of the major sectors were up with the exception of Pulp & Paper.

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 Weather and Demand Summary

	Historical Analysis	May	June	July	August	September	October	November
Actual Weather	Average Temperature (°C)	22.3	24.2	28.0	27.3	22.3	12.1	3.5
	Minimum Temperature (°C)	10.2	15.0	21.9	18.4	9.9	5.2	-6.6
	Maximum Temperature (°C)	30.7	34.8	34.1	34.3	33.9	28.6	15.4
Normal Weather	Normal Average Temperature (°C)	17.1	23.8	26.4	24.4	20.9	12.6	6.7
	Normal Minimum Temperature (°C)	8.7	13.4	20.0	18.2	9.5	4.0	-2.0
	Normal Maximum Temperature (°C)	27.2	31.3	30.9	30.8	29.8	21.1	18.9
Actual Demand	Peak Demand (MW)	20,473	21,369	23,046	21,990	23,131	18,640	20,048
	Average Hour (MW)	14,007	15,171	17,050	17,055	15,525	14,521	15,831
	Minimum Hour (MW)	10,541	10,698	11,413	11,966	10,809	11,052	12,050
	90th Percentile (MW)	16,770	18,437	20,705	20,623	19,597	16,419	17,927
	Percent above 20,000 (MW)	1.4%	5.2%	18.9%	16.2%	7.9%	0.0%	0.1%
	# of Hours Above 20,000 (MW)	10	37	141	121	57	-	1
	Energy Demand (GWh)	10,421	10,923	12,685	12,689	11,178	10,803	11,398
Weather Corrected Demand	Peak Demand (MW)	18,997	20,197	22,572	21,459	19,784	18,036	19.243
	Energy Demand (GWh)	10,282	10,868	12,352	12,112	10,711	10,619	11,045
Forecast Demand	Peak Demand (MW)	18,817	21,890	22,076	21,946	19,019	17,788	19,828
	Energy Demand (GWh)	10,290	10,863	11,653	11,686	10,190	10,750	11,171

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 down into its two main components, summer (June, July and August) and fall (September, October and November).

The weather over the summer was warmer than normal. Compared to the previous summer energy demand was up 8.2 percent and down 0.9 percent compared to the summer of 2016. After adjusting for the weather the increase versus 2017 was 4.6 percent and the decline versus 2016 was 0.7 percent.

Distributors' loads followed a similar pattern. For the summer of 2018 they were up 9.3 percent over the previous summer but 1.0 percent lower than the summer of 2016. After making the weather adjustments, the increase was 4.9 percent over 2017 and a decline of 0.6 percent compared to 2016. The output of embedded generation was slightly higher in the summer of 2017 (1.72 GWh) than both 2016 (1.69 GWh) and 2018 (1.65 GWh). However, that only accounts for a small portion of the drop in load during the summer of 2017.

For the summer months, wholesale loads showed an increase of 1.1 percent compared to the previous summer. Once again, this growth is tempered when comparing back to 2016 which then shows a 1.0 percent decline. Mining, petrochemicals and autos drove the growth in the summer of 2018.

Like the summer, demand for the fall was heavily influenced by the weather. The colder than normal weather pushed demand for the fall up by 4.4 percent over the fall of 2017 and 3.4 percent above the fall of 2016. After adjusting for weather, fall demand was up 2.1 percent over 2017 and down 0.1 percent from 2016. Once again this shows how 2018 is the continuation of the post-recession trend while 2017 appears to be an anomaly. The distributor loads showed an actual increase of 4.2 percent and a 1.5 percent increase after correcting for weather. Once again this represents an increase over the fall of 2017 but was only a 0.7 percent increase in actuals over 2016 (0.1% decline using weather corrected data).

Wholesale customers' loads increased by 3.8 percent compared to the previous fall and a . Consumption for the iron and steel sector showed strong growth, motor vehicle production load was flat but the remaining sectors showed declines compared to the previous fall.

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 down 0.9 percent compared to last year. Year-to-date embedded generation output is 5.9 TWh. The growth rate has slowed in concert with the growth in capacity has slowed.

For the six months from June to November, distributors' loads increase by 6.8 percent compared to the same six-month period in 2017 and a 1.7 percent increase against 2016. Weather corrected values were 3.3 percent increase versus 2017 and a 0.4 percent decline versus 2016. Embedded generation decreased by a same 5.9 percent for the same period a year ago.

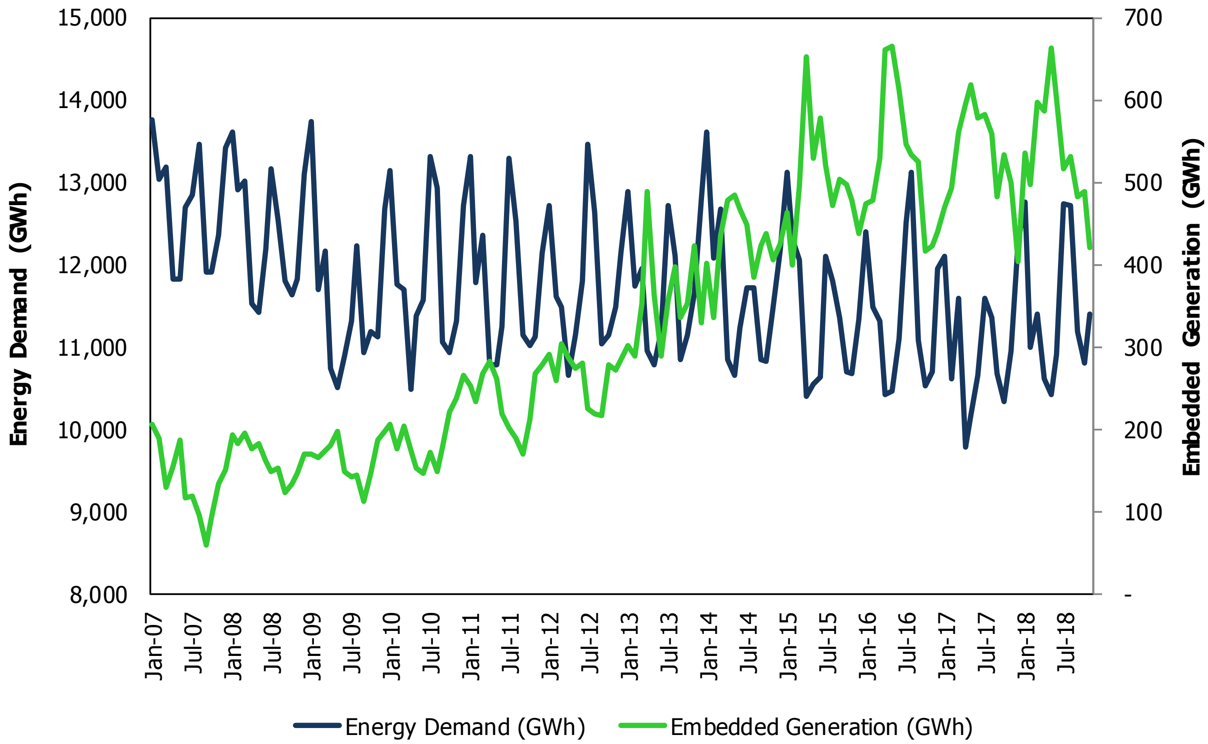

Figure 3-7| Monthly Weather-Corrected Distributor Load and Embedded Generation Output

Figure 3.8 shows the year-over-year change in wholesale customers' average hourly consumption. The graph traces the impact of the recession, 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 each of 2008 and 2018 year to date. Only the mining sector is above its pre-recession levels. All the other major sectors saw a significant decline in 2009 and relative stability since. Some of the change is due to the economic cycle whereas others are sector specific. The decline in demand for newsprints on pulp and paper is sector specific and explains the decline there. Wholesale loads declined by 24 percent in 2009 and now sit 9 percent above that recessionary low.

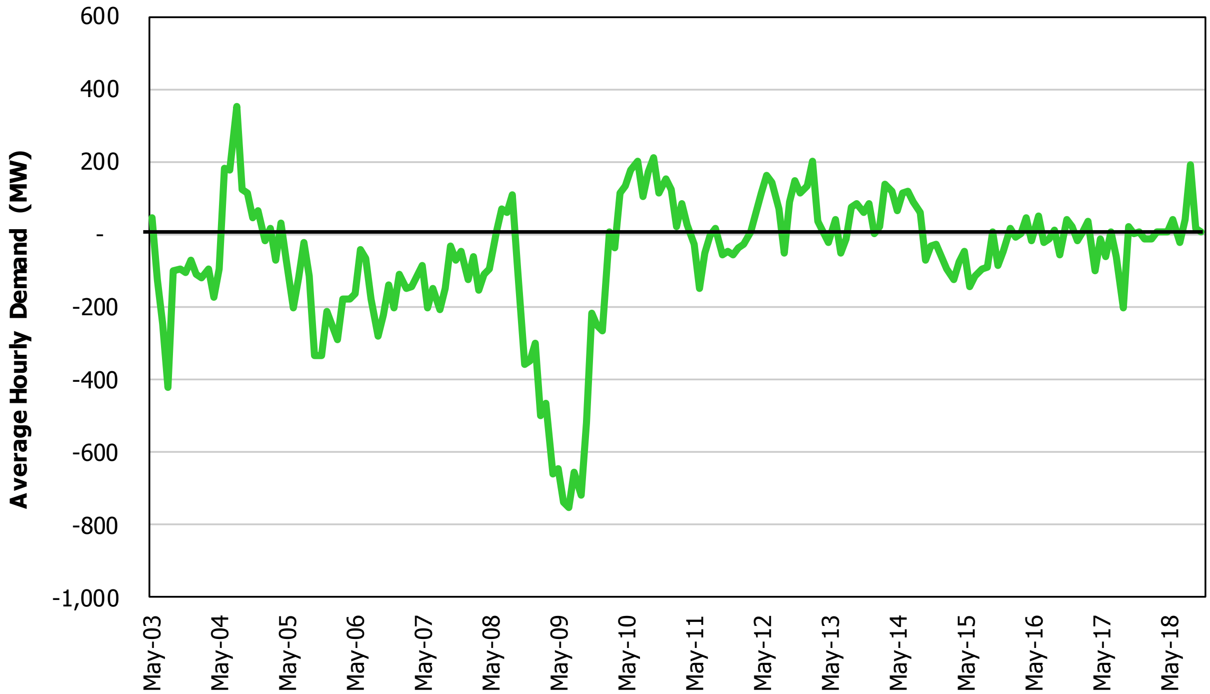

Figure 3-8 | Wholesale Customers' Year-over-Year Change in Consumption

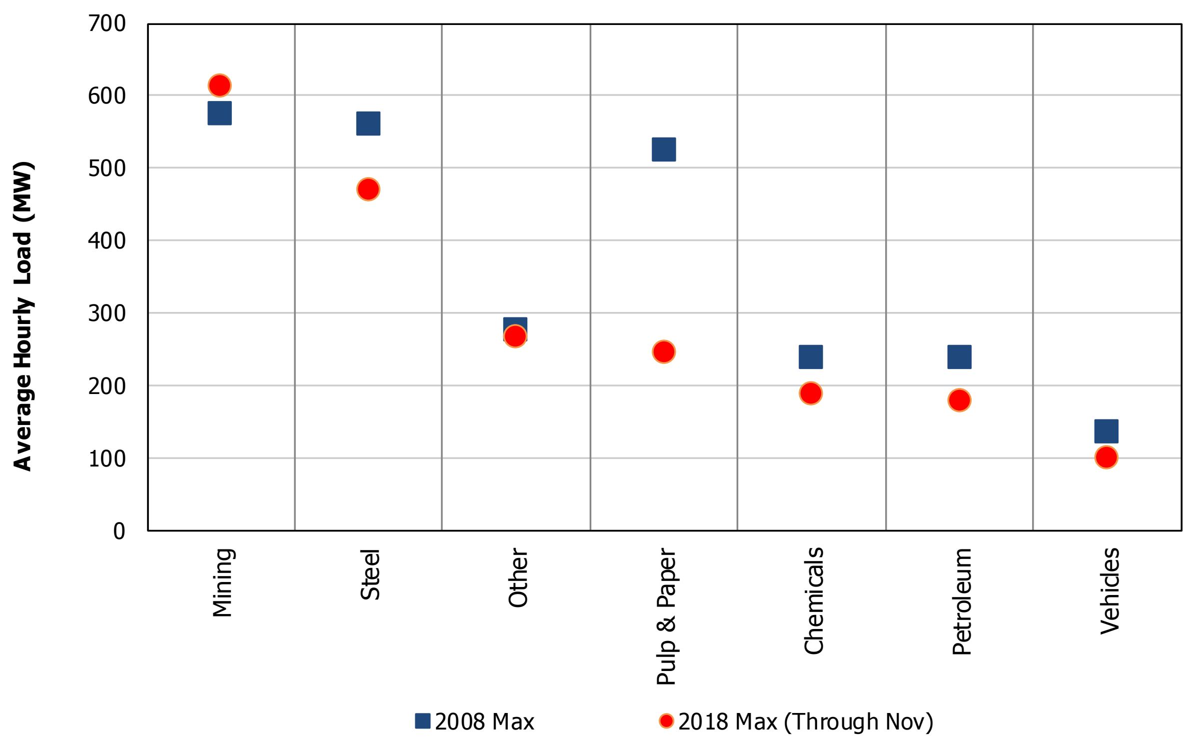

Figure 3-9 | Wholesale Customers' Average Hourly Consumption by Industry Segment

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, it means that the 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	10-Jun-18	08-Jun-18	2,332	2,334	
24	17-Jun-18	17-Jun-18	2,570	3,554	
25	24-Jun-18	18-Jun-18	2,590	2,596	
26	01-Jul-18	29-Jun-18	2,800	2,754	
27	08-Jul-18	05-Jul-18	2,918	2,830	Canada Day
28	15-Jul-18	15-Jul-18	2,959	2,883	
29	22-Jul-18	16-Jul-18	2,807	2,726	
30	29-Jul-18	24-Jul-18	2,805	2,710	
31	05-Aug-18	03-Aug-18	2,904	2,790	
32	12-Aug-18	07-Aug-18	2,886	2,734	Civic Holiday
33	19-Aug-18	15-Aug-18	2,948	2,778	
34	26-Aug-18	20-Aug-18	2,701	2,560	
35	02-Sep-18	28-Aug-18	2,867	2,747	
36	09-Sep-18	05-Sep-18	2,762	2,555	Labour Day
37	16-Sep-18	16-Sep-18	2,679	2,561	
38	23-Sep-18	17-Sep-18	2,580	2,465	
39	30-Sep-18	25-Sep-18	2,380	2,392	
40	07-Oct-18	02-Oct-18	2,394	2,393	
41	14-Oct-18	09-Oct-18	2,398	2,337	Thanksgiving Day
42	21-Oct-18	17-Oct-18	2,410	2,291	
43	28-Oct-18	24-Oct-18	2,514	2,452	
44	04-Nov-18	29-Oct-18	2,502	2,489	
45	11-Nov-18	09-Nov-18	2,556	2,530	Remembrance Day
46	18-Nov-18	14-Nov-18	2,700	2,566	
47	25-Nov-18	22-Noc-18	2,739	2,726	

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 23,374 MW, which was the highest peak since 2013. The peak weather was warmer than the previous summer. The weather-corrected summer peak was also the highest since 2013.

The fall peak was 23,131 MW, which was significantly higher than the previous fall peak (21,786 MW). This fall's peak occurred during hot weather (33.9 °C) early in September whereas the fall of 2017 had a warm weather peak (31.3 °C) much later in the month. The timing will influence the peak as fewer people will be running their air condition on September 25 than September 5.

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 as the program applies to Class A customers -- that includes 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. This change will enable large commercial facilities to access the program. Those between 0.5 MW and 1 MW are still restricted to specific sectors: manufacturing, greenhouses and floriculture.

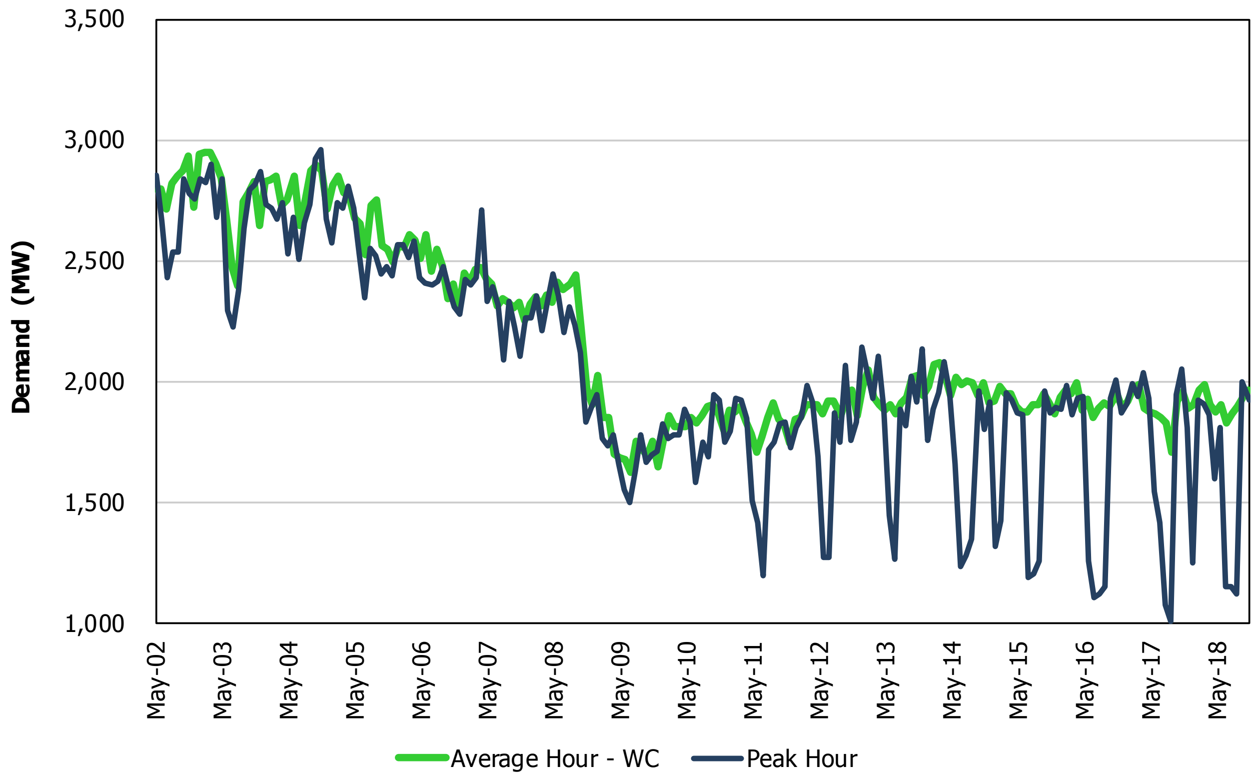

Figure 3-10 | Wholesale Customers' Coincident Peak and Average Hourly Consumption

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.

Figure 3.11 shows the winter weekday peaks levels in MW and the hour in which they occurred for the winter of 2005, 2016 and the winter of 2018. The graph clearly shows how peaks are lower today – a result of conservation and lower industrial load – but that the peaks occur in the same timeframe from hours 18-20. Figure 3.12 shows the weekday peaks in MW and the hour in which they occurred for the summer of 2005, 2016 and 2018. Here the peaks are once again lower but in the case of the summer, the hours at which those peaks are occurring have changed. Generally, the peaks have shifted to later in the day. In 2004, twelve weekday peaks occurred at hour ending 17 (5 p.m. EST) or later. By 2018, the number of peaks in that time frame had increased to fifty-five. The contrast between the summer and winter distribution of peak hours shows the impact that embedded solar in having on the summer peaks. Embedded solar is making the summer peaks lower and later in the day.

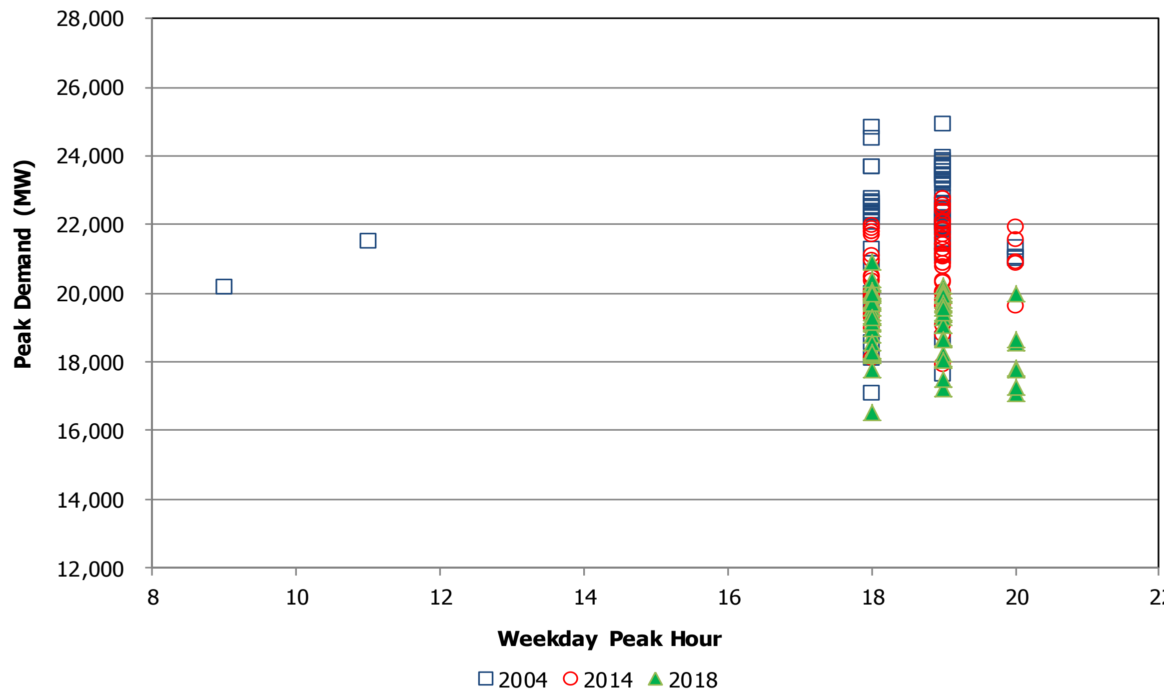

Figure 3-11 | Seasonal Weekday Peak Hour Distribution - Winter

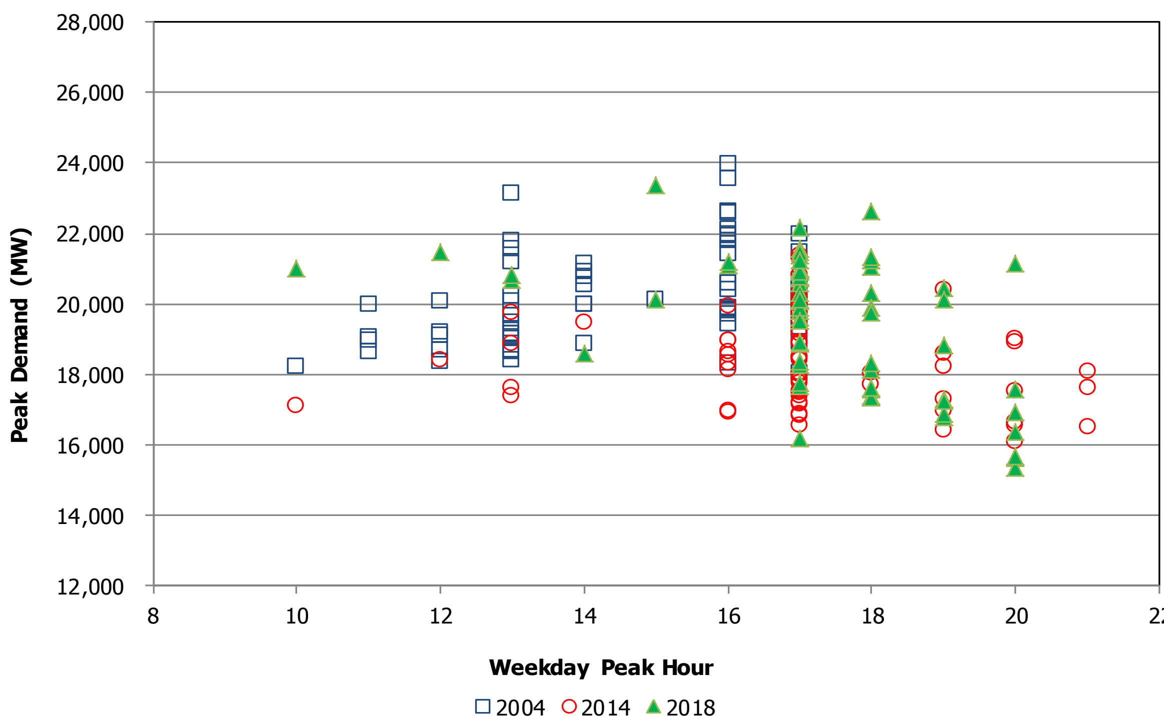

Figure 3-12 | Seasonal Weekday Peak Hour Distribution – Summer

The interesting aspect of the seasonal peaks is that the winter peak has less underlying growth, but fewer factors are acting to mitigate that growth, while the summer peak has greater underlying growth but more factors working to reduce them.

Figure 3.13 shows the break-down for the past two summer and winter peaks. For the past two winters ICI has not been a factor. As well, for all of the seasonal peaks depicted it was only during the summer peaks where demand response was activated. 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 very low level of embedded generation output as it peak occurred late in the day, late in September.

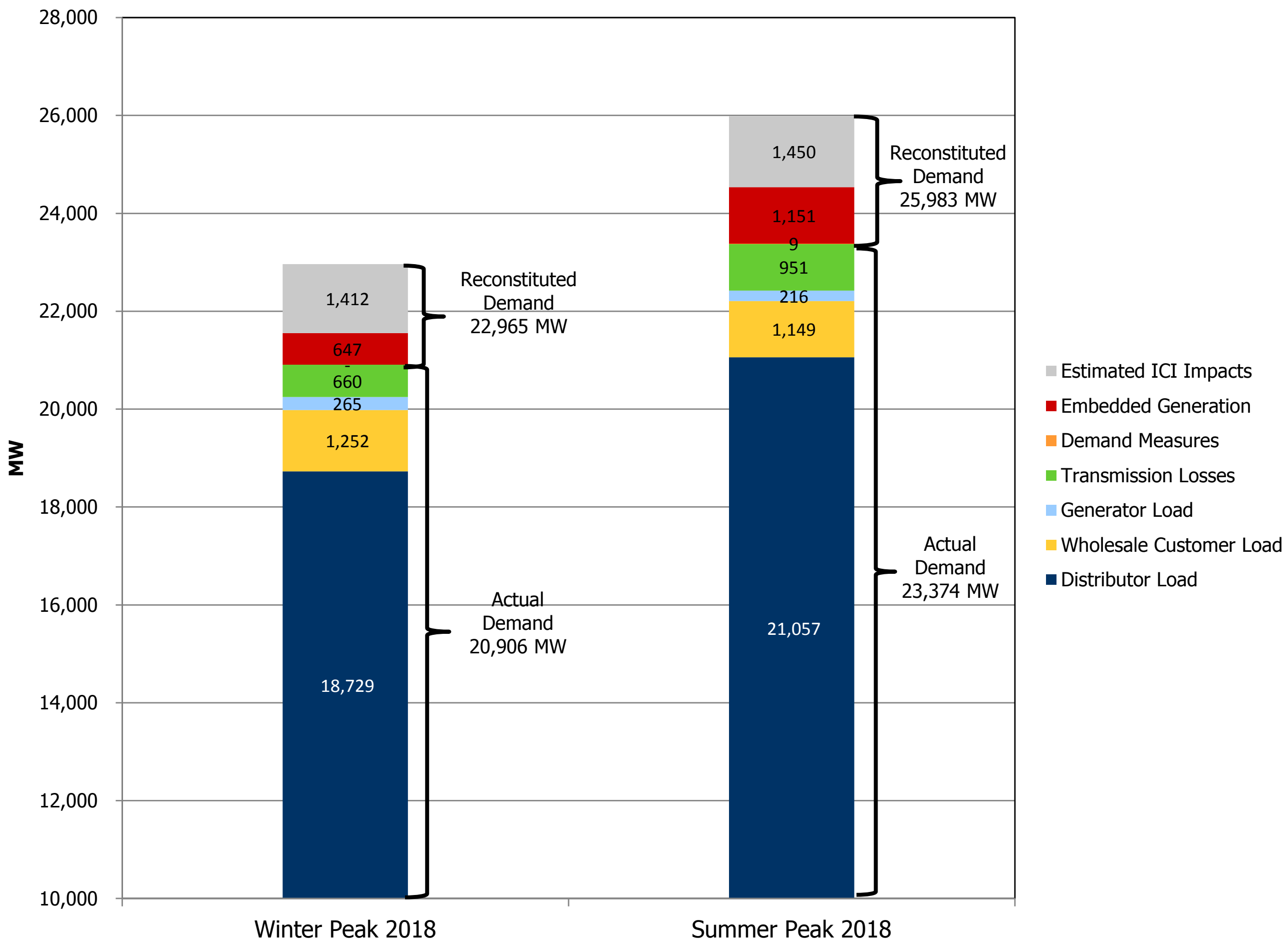

Figure 3-13 | Anatomy of Seasonal Peaks

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	10-Jun-18	08-Jun-18	16,765	16,679	21.9
24	17-Jun-18	17-Jun-18	20,161	19,585	31.3
25	24-Jun-18	18-Jun-18	20,992	20,125	30.2
26	01-Jul-18	29-Jun-18	21,037	20,197	31.0
27	08-Jul-18	05-Jul-18	23,374	22,572	33.2
28	15-Jul-18	15-Jul-18	21,510	20,921	29.9
29	22-Jul-18	16-Jul-18	21,455	20,924	31.5
30	29-Jul-18	24-Jul-18	21,545	20,845	29.5
31	05-Aug-18	03-Aug-18	21,028	20,453	28.5
32	12-Aug-18	07-Aug-18	21,190	20,313	27.5
33	19-Aug-18	15-Aug-18	21,456	20,621	30.9
34	26-Aug-18	20-Aug-18	20,142	18,754	25.0
35	02-Sep-18	28-Aug-18	22,175	21,459	31.7
36	09-Sep-18	05-Sep-18	23,131	19,784	33.9
37	16-Sep-18	16-Sep-18	20,871	19,019	28.3
38	23-Sep-18	17-Sep-18	21,233	18,793	26.3
39	30-Sep-18	25-Sep-18	17,419	17,669	20.4
40	07-Oct-18	02-Oct-18	16,841	16,932	12.9
41	14-Oct-18	09-Oct-18	18,640	17,024	28.6
42	21-Oct-18	17-Oct-18	17,040	16,504	8.5
43	28-Oct-18	24-Oct-18	17,481	17,246	5.2
44	04-Nov-18	29-Oct-18	17,267	17,380	8.5
45	11-Nov-18	09-Nov-18	18,209	17,983	2.6
46	18-Nov-18	14-Nov-18	19,232	19,083	0.3
47	25-Nov-18	22-Nov-18	20,048	19,243	-6.6

3.4 Load Duration Curves

The following load duration curves display load for the four seasons. The seasons are defined as: fall (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 2018 was low by historical standards.

For the summer curve the graph also includes the load duration curve for 2016. This highlights the similarity between the two summers of 2016 and 2018.

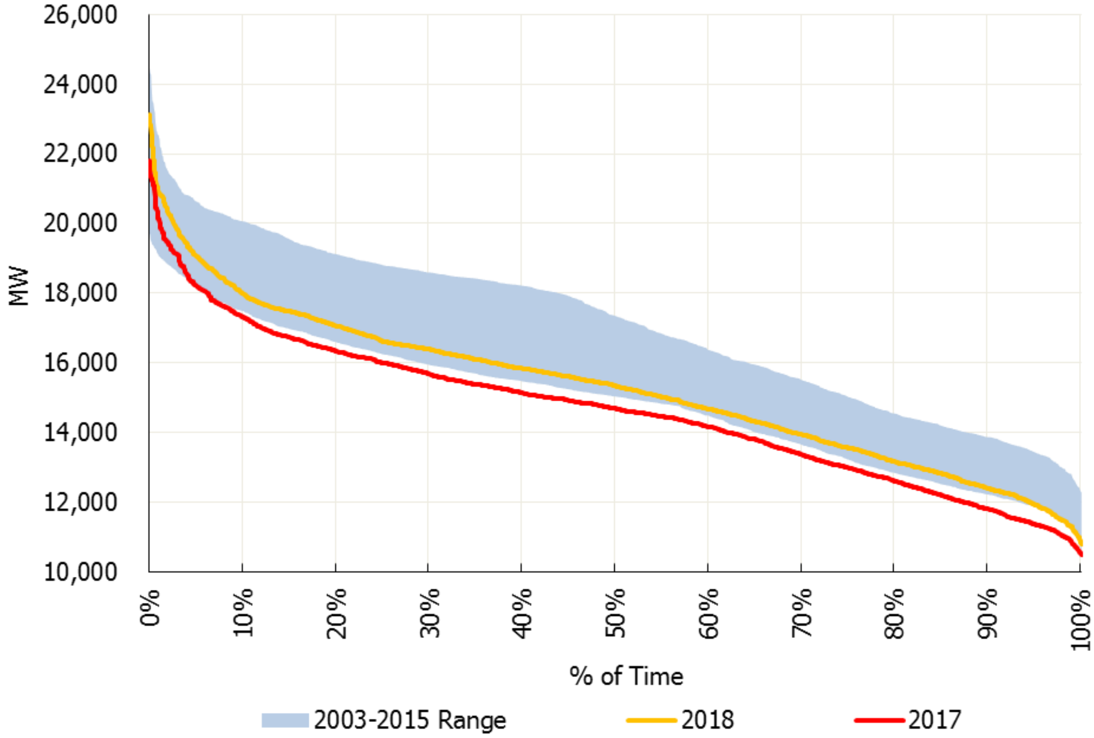

Figure 3-14 | Fall Load Duration Curve

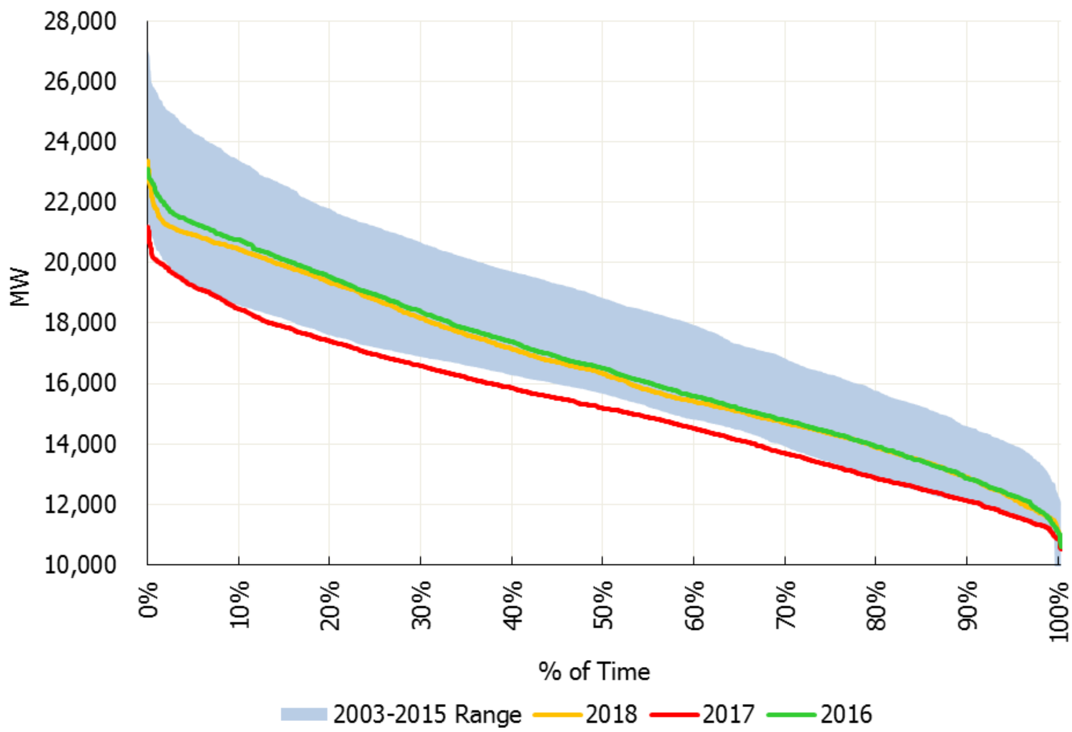

Figure 3-15 | Summer Load Duration Curve

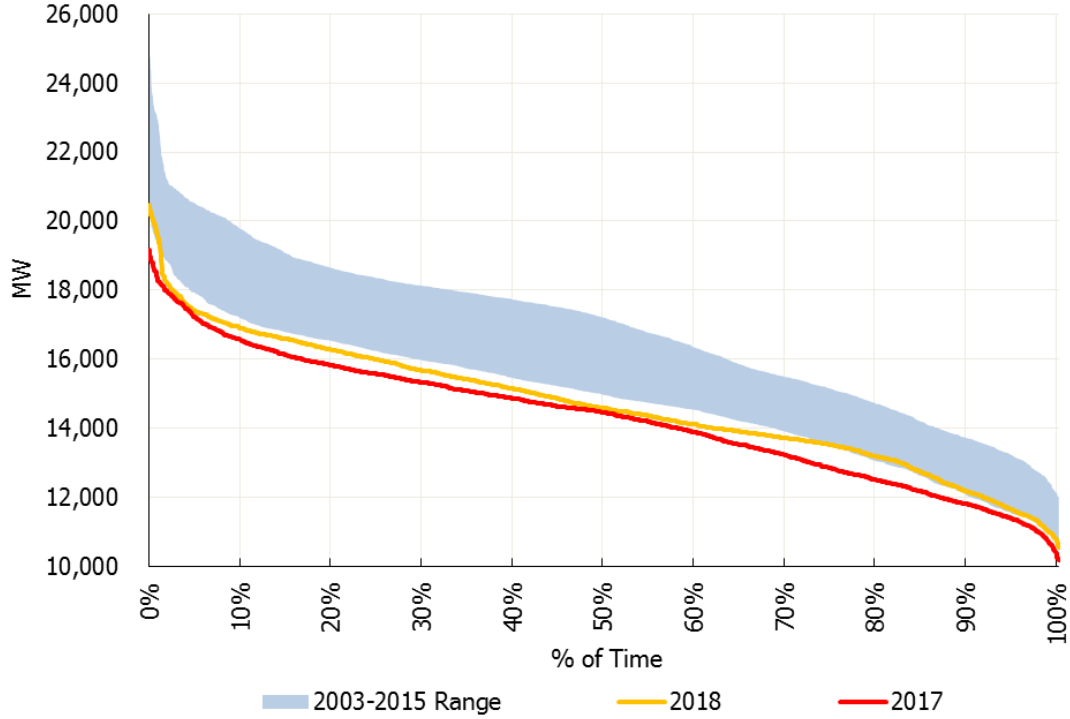

Figure 3-16 | Spring Load Duration Curve

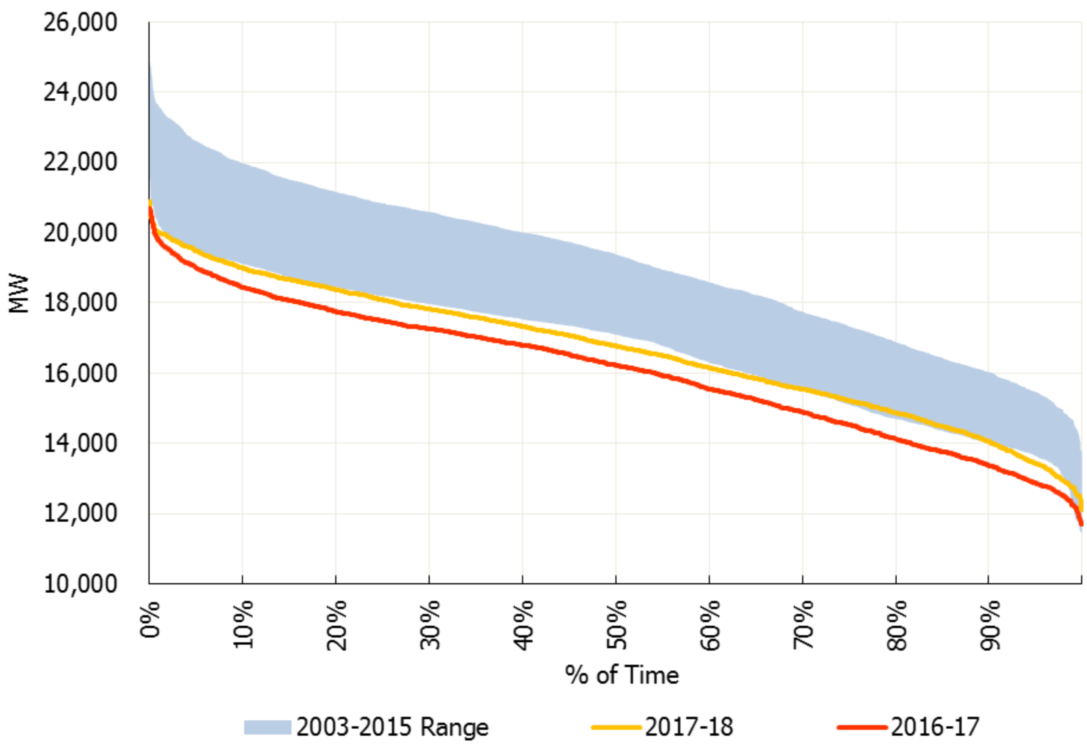

Figure 3-17 | Winter Load Duration Curve

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. 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 June 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 to 2016 time frame. The squares represent the weekly minimums for the past six months.

The minimums of the past six months reflect the generally warmer weather and higher levels of demand throughout 2018. Unlike 2017, the weekly minimums for 2018 have only reached new lows on a couple of occasions. The weekly minimums occur during the early morning hours of the weekend, when the level of economic activity is lowest.

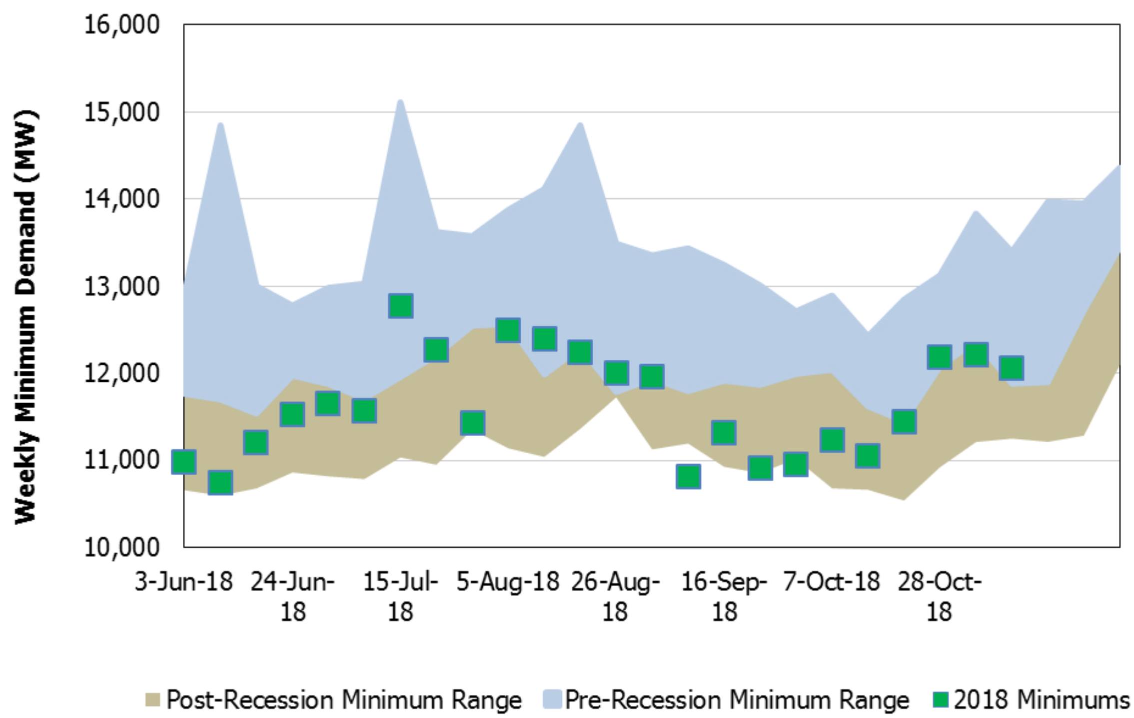

Figure 3-18 | Weekly Minimum Demands

4. Forecasting Process and Assumptions

A detailed description of the forecasting methodology can be found in the document entitled "Methodology to Perform the Reliability Assessment."

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. Forecasting demand for electricity according to the calendar – days of the week, holidays, sunrises and sunsets – is relatively 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.

Canada continues to benefit from strong economic fundamentals - low interest rates, a low exchange rate, strong corporate profits, robust consumer demand and strong U.S. growth. This should benefit both Canada and Ontario over the forecast horizon. However, there are substantial risks over the Outlook period. Consumption is the largest sector of the economy and is driven by consumer and business confidence. Consumer confidence dropped significantly during the summer of 2018 as the NAFTA negotiations highlighted tensions between the North American participants. With the agreement in principal of the updated trade deal, confidence bounced back later in the fall. It does highlight the volatile nature of consumer confidence. With on-going steel and aluminum tariffs, a U.S.-China trade war and the GM Oshawa news, confidence could revert to a more-pessimistic stance with negative impacts for the economy.

Ontario's economy has seen modest growth throughout 2018. Many of the sectors that have driven growth this year 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.

Through the first eleven months of 2018 Ontario's employment has grown by 1.6 percent overall, but manufacturing employment has declined by 0.1 percent compared to 2017. This is a stark contrast to 2017 where overall employment increased 1.8 percent and manufacturing employment increased by 2.1 percent.

Figure 4.1 shows the year-over-year changes in employment broken down into services, manufacturing and other goods (mining, construction, agriculture, forestry, etc.). A broad-based and sustainable growth pattern would have growth across all of the sub-sectors. Throughout 2017 employment growth showed that broad based growth across all sectors but that dissipated as 2018 unfolded. Most of 2018's employment growth has centered in services (1.6%) and construction (2.6%). The recent announcement regarding the closure of the General Motors plant in Oshawa will require continued monitoring and further study as more information becomes available. Assessing the economic impacts and timing will hinge on developments over the next year. The closure could have substantial economic impacts on many of the supplier industries starting in 2020.

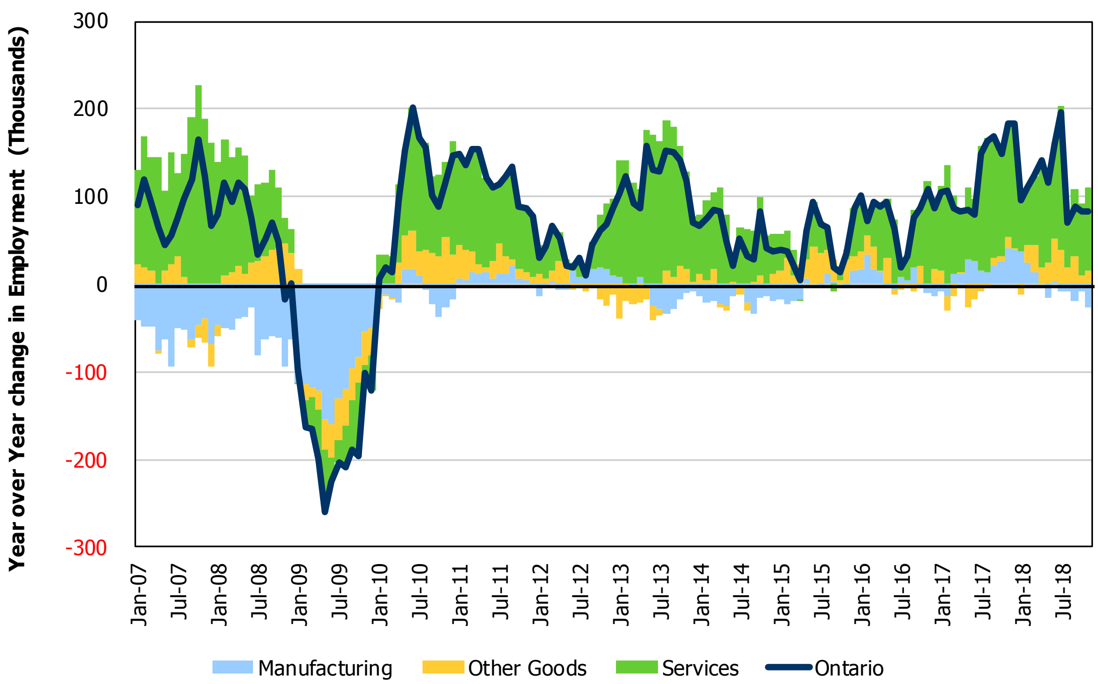

Figure 4-1 | Composition of Ontario's Employment Growth

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 on the province For 2018 job growth has been fairly balanced across the province. Figure 4.2 shows the year over year employment change for Toronto and the rest of the province.

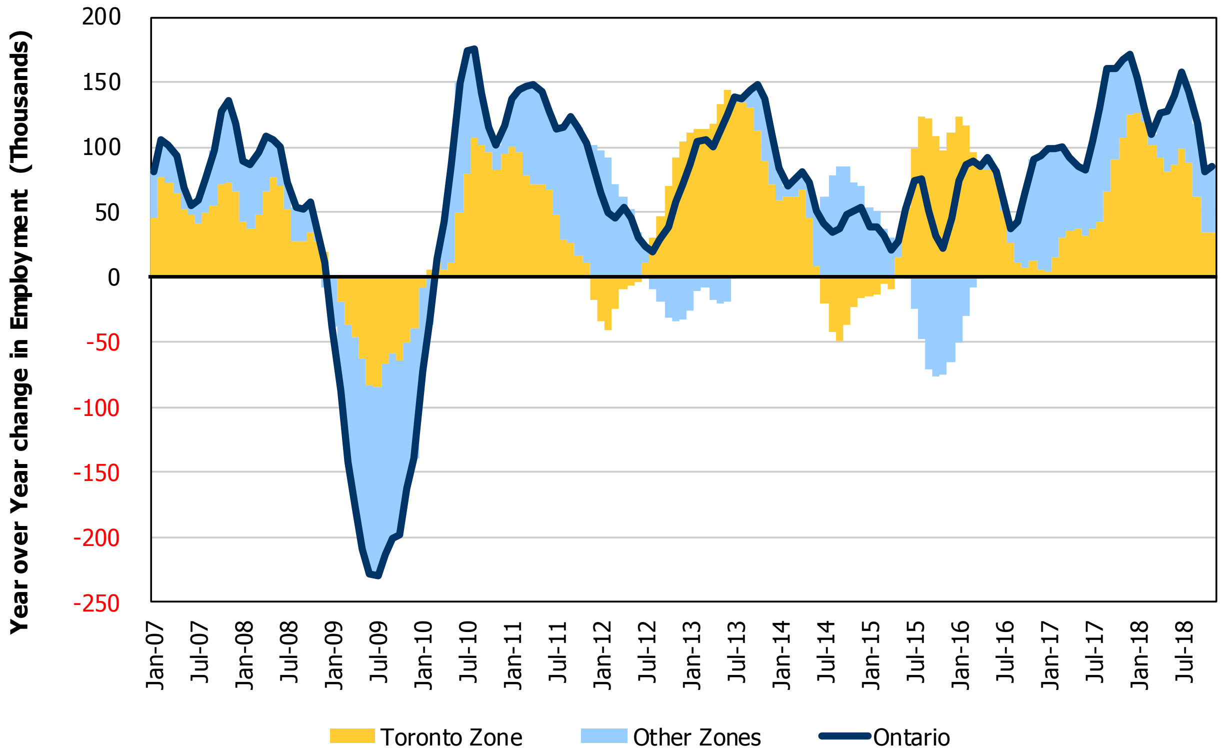

Figure 4-2 | Zonal Employment Growth

Combined the actual job growth for 2018 is somewhat mixed. It is balanced geographically, but is lower than 2017 and is being driven by the service sector.

Additionally, the economy has experienced a long period of expansion since the 2009 recession. Although the recovery period was very modest compared to similar historical post-recession periods, the economy has seen consistent, if modest, growth. Increasing interest rates, on-going trade tensions and slowing employment growth could translate into an end of the current economic growth cycle. Whether this occurs within the forecast horizon of this outlook is something to consider.

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	1.75	1.00
2016	6,999	1.1	73.6	7.8	1.392	1.26
2017 (f)	7,107	1.5	78.4	6.5	1.413	1.52
2018 (f)	7,189	1.2	70.8	-9.7	1.431	1.24
2019 (f)	7,253	0.9	68.7	-3.0	1.446	1.08

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 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. The weather scenarios were updated for data through the end of December 2012.

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 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 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.

As of the end of October 2018 the Capacity Backed Demand Response program expired Those who previously participated in the program are eligible to participate in the Demand Response Auction.

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 1,400 MW for the five peak days in 2017. The preliminary estimate for the ICI impact on the 2018 peak is 1,450 MW. That estimate will be finalized at the end of the ICI year.

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. All output provided by embedded generation is an offset to grid-supplied electricity. Therefore, the impact of embedded generation is factored into the 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 Reliability Outlook Tables.

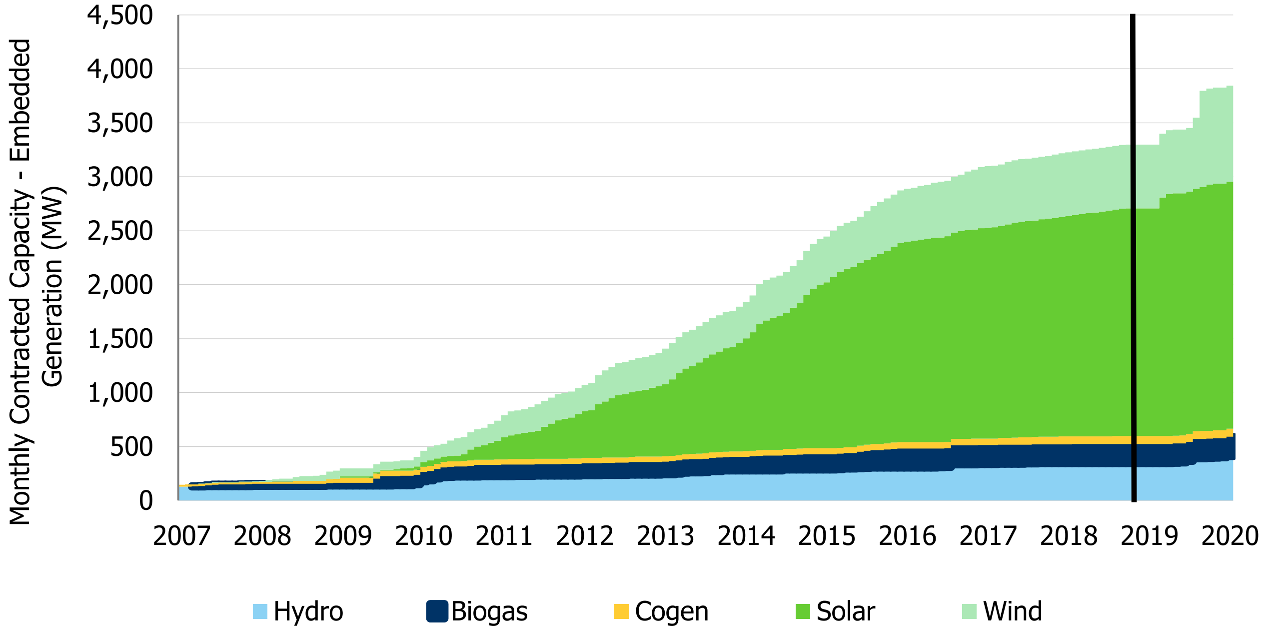

Figure 4-3 | Projected Embedded Generation Capacity

Table 4-2 | Estimate of Contracted Embedded Generation Capacity (MW)

Month	Biogas	Cogen	Hydro	Solar	Wind	Total
Jun-07	14	18	132	0	7	171
Jun-08	20	25	134	0	38	218
Jun-09	61	49	139	10	74	335
Jun-10	94	49	220	53	160	576
Jun-11	108	49	229	262	241	890
Jun-12	114	49	235	579	298	1,275
Jun-13	125	49	259	848	335	1,616
Jun-14	137	55	279	1239	373	2,083
Jun-15	153	55	298	1694	430	2,630
Jun-16	176	60	306	1897	515	2,954
Jun-17	176	67	341	1999	580	3,164
Jun-18	177	73	345	2082	591	3,268
Jun-19	178	73	352	2246	591	3,439
Jun-20	179	78	412	2287	1051	4,005

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.

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