Ontario Demand Forecast

JUNE 21, 2016

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Executive Summary

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid 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 2016 to December 2017 and supersedes the previous forecast released in March 2016.

Economic Outlook

After six years of the post-recession economic doldrums, it appears that the Ontario economy is gaining some traction. This is due to two main factors -- strong U.S. growth combined with a lower dollar. The U.S. economy experienced a bit of a bounce back in 2010 but growth lagged in 2011 and 2012. However, since that time the American economy has seen fairly robust growth. At the time of the financial crisis, the Canadian dollar was priced in the high 90s. The Canadian dollar dropped in the aftermath of the financial crash but, as the U.S. Federal Reserve embarked on a program of aggressive quantitative easing, the Canadian dollar appreciated substantially, rising above parity. The dollar held its ground, valued at the mid-90¢ mark into mid-2014. The price of crude oil began to drop midway through 2014 and with it, the Canadian dollar started to slide. By the end of 2015, the dollar was 22 percent below its pre-recession mark. The combination of increased demand for goods and services from Canada's largest trading partner and an increase in cost competitiveness certainly is a boon to Ontario's economy.

The signs are positive for continued economic growth throughout 2016. So far this year, both the employment and output numbers have been mostly positive. This is true both for the overall economy but also for the industrial sector as well. This is relevant to electricity demand as manufacturing is much more energy intensive than the broader economy. Therefore, stronger growth in the manufacturing sector over 2016 and 2017 will lead to an increase in the underlying electricity demand. Offsetting some of those gains will be increased output from embedded generators and savings from conservation initiatives.

The post recessionary period has been characterized by the atypical sluggish growth seen during the recovery period. Much of this has been a result of the lingering fragility due to high consumer and sovereign debt, slower growth and lower consumer confidence. There still exist a number of threats to the global economic equilibrium. Concerns over whether Britain will withdraw from the European Union and slowing Chinese growth could have market impacts over the coming summer.

Actual Weather and Demand

Since the last Ontario Demand Forecast document was published, actual demand and weather data have been reported for the six months of December through May. Demand for the six-month period was down 4.5 percent over the same period a year earlier.

However, the weather had a big impact and, after weather correcting, the decline is a much smaller 1.0 percent.

For the past six months, distributor loads have dropped by 5.3 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. However after adjusting for weather, distributor loads showed a much smaller 1.1-percent decline. This is a product of the mild 2015-16 winter. However, the numbers are further clouded by the fact that February 2016 had an extra day. Once adjusted for both the weather and the calendar, demand for the period slipped by 1.7 percent.

Over the same period, wholesale customers' consumption increased by 0.4 percent, reversing a trend of year-over-year decreases for 13 of the 14 previous months. After adjusting for the additional leap day, wholesale customers' consumption actually showed a small 0.1-percent decline. However, consumption appears to be strengthening as load has been higher in the spring than in the winter.

The 2015-16 winter peak demand occurred on January 4, which was the coldest day of the month but was sandwiched between two fairly mild days. This could have contributed to the fact that the winter peak was the lowest since market opening. Since the peak day was only slightly warmer than normal, the weather-corrected peak was only slightly higher at 21,158 megawatts (MW); this was also the lowest weather-corrected winter peak since market opening. The afternoon high was -11.8°C (Toronto) for the winter peak. The February peak was very close to the winter peak (20,766 MW) and occurred under similar weather conditions (-10.0 °C). The winter weather was mild by historical standards, with December in particular being historically warm.

The weather over the course of the spring was a bit of a mixed bag. March was warmer than normal, April much colder than normal and May was warmer than normal. Since spring peaks can be either cold- or warm-weather driven, the timing of weather plays a key role. In the case of spring 2016, the cold temperatures of early March (-7.9°C) had a much bigger impact than the warm temperatures of late May (27.9°C). This seems to be the pattern over the last couple of years as the winter weather has been mild – particularly at the beginning of winter – with cold weather drifting into early spring. Recent spring weather has been cooler than normal.

Demand Forecast

The 18-Month Outlook's demand forecast includes the impact of additional conservation savings and demand reductions from projected off-grid or embedded generation. In the 18-Month 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 be virtually flat 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, Industrial Conservation Initiative (ICI) impacts and growth in solar embedded generation.

Grid-supplied energy demand is expected to show a small increase in 2016 though once adjusted for the additional leap day, this translates into a small decline. As the economy picks up throughout 2016 and into 2017, electricity demand will show a small increase in 2017.

Table 1: Peak and Energy Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2016	22,600	24,740
Winter 2016-17	22,201	23,213
Summer 2017	22,680	24,859
Year	**Normal Weather Energy (TWh)**	**% Growth in Energy**
2006 Energy	152.3	-1.9%
2007 Energy	151.6	-0.5%
2008 Energy	148.9	-1.8%
2009 Energy	140.4	-5.7%
2010 Energy	142.1	1.2%
2011 Energy	141.2	-0.6%
2012 Energy	141.3	0.1%
2013 Energy	140.5	-0.6%
2014 Energy	138.9	-1.1%
2015 Energy	136.5	-1.7%
2016 Energy (Forecast)	136.7	0.1%
2017 Energy (Forecast)	137.4	0.5%

- 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 this requirement and covers the period from July 2016 to December 2017. It supersedes the previous forecast released in March 2016 and the previous Ontario Demand Forecast document released in December 2015.

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/Documents/marketReports/Methodology_RTAA_2016jun.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 March 2016. Data for April and May 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/Documents/marketReports/18MonthOutlookTables_2016jun.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.

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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-Jul-16	22,316	24,091	1,016	2,675					
10-Jul-16	22,600	24,740	814	2,765	09-Apr-17	18,009	18,694	471	2,520
17-Jul-16	22,490	23,789	838	2,656	16-Apr-17	17,296	18,241	496	2,415
24-Jul-16	22,167	24,229	1,035	2,748	23-Apr-17	16,724	16,814	531	2,405
31-Jul-16	22,228	24,316	841	2,735	30-Apr-17	16,708	17,250	721	2,394
07-Aug-16	21,440	24,466	958	2,703	07-May-17	17,476	20,387	849	2,357
14-Aug-16	21,214	24,152	985	2,677	14-May-17	17,657	19,903	845	2,375
21-Aug-16	21,244	23,817	1,362	2,706	21-May-17	18,555	21,983	1,175	2,398
28-Aug-16	20,239	22,902	1,413	2,570	28-May-17	18,613	22,112	1,330	2,339
04-Sep-16	18,766	22,285	1,370	2,472	04-Jun-17	19,170	21,691	1,292	2,438
11-Sep-16	18,302	20,791	680	2,438	11-Jun-17	19,844	24,141	1,055	2,570
18-Sep-16	17,969	20,136	781	2,462	18-Jun-17	20,919	24,300	835	2,584
25-Sep-16	17,079	18,506	420	2,385	25-Jun-17	22,269	24,381	754	2,651
02-Oct-16	17,252	17,409	554	2,439	02-Jul-17	22,219	24,005	1,016	2,639
09-Oct-16	17,143	17,551	786	2,463	09-Jul-17	22,680	24,859	814	2,739
16-Oct-16	17,645	18,203	507	2,413	16-Jul-17	22,339	24,012	838	2,777
23-Oct-16	17,735	18,441	392	2,498	23-Jul-17	22,132	23,980	1,035	2,673
30-Oct-16	18,166	18,878	318	2,526	30-Jul-17	22,187	24,752	841	2,758
06-Nov-16	18,442	19,216	416	2,593	06-Aug-17	22,413	24,505	958	2,773
13-Nov-16	19,145	20,049	601	2,618	13-Aug-17	22,005	24,629	985	2,728
20-Nov-16	19,753	20,568	342	2,688	20-Aug-17	21,390	24,427	1,362	2,700
27-Nov-16	20,276	21,300	607	2,743	27-Aug-17	21,423	23,596	1,413	2,708
04-Dec-16	20,406	21,725	409	2,773	03-Sep-17	20,623	23,145	1,370	2,590
11-Dec-16	20,906	21,827	555	2,815	10-Sep-17	18,934	22,292	680	2,440
18-Dec-16	20,913	21,811	690	2,816	17-Sep-17	19,418	21,107	781	2,502
25-Dec-16	20,514	22,329	362	2,875	24-Sep-17	18,141	20,200	420	2,474
01-Jan-17	20,413	21,225	528	2,690	01-Oct-17	17,350	18,726	554	2,409
08-Jan-17	21,518	22,308	570	2,850	08-Oct-17	17,531	17,638	786	2,453
15-Jan-17	22,201	23,213	547	2,932	15-Oct-17	17,477	17,520	507	2,435
22-Jan-17	21,775	22,173	483	2,921	22-Oct-17	17,923	18,332	392	2,476
29-Jan-17	21,549	22,382	404	2,925	29-Oct-17	18,022	18,575	318	2,517
05-Feb-17	21,175	22,316	734	2,931	05-Nov-17	18,282	18,944	416	2,519
12-Feb-17	20,694	22,149	635	2,874	12-Nov-17	19,321	19,846	601	2,623
19-Feb-17	20,191	21,745	581	2,823	19-Nov-17	19,659	20,314	342	2,647
26-Feb-17	20,096	21,842	501	2,773	26-Nov-17	20,088	20,751	607	2,718
05-Mar-17	20,265	21,520	531	2,790	03-Dec-17	20,545	21,482	409	2,767
12-Mar-17	20,018	20,879	649	2,756	10-Dec-17	20,740	21,722	555	2,790
19-Mar-17	18,933	19,666	611	2,674	17-Dec-17	21,036	21,934	690	2,831
26-Mar-17	18,461	19,231	569	2,586	24-Dec-17	20,885	21,824	362	2,802
02-Apr-17	18,371	19,373	567	2,563	31-Dec-17	20,569	21,584	528	2,702

Compared to the previous forecast, the peak and energy demand are lower throughout the first part of 2016 and higher in the latter part.

Figure 2.1: Weekly Energy Demand – History and Forecast

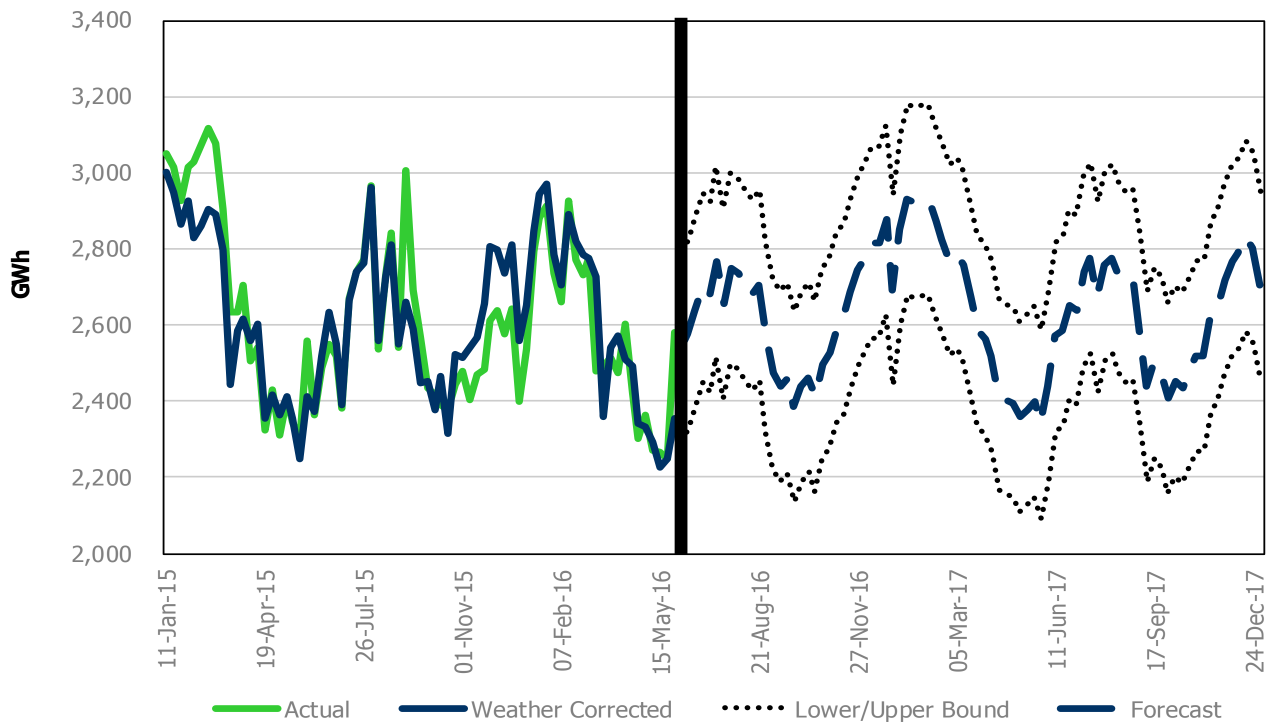
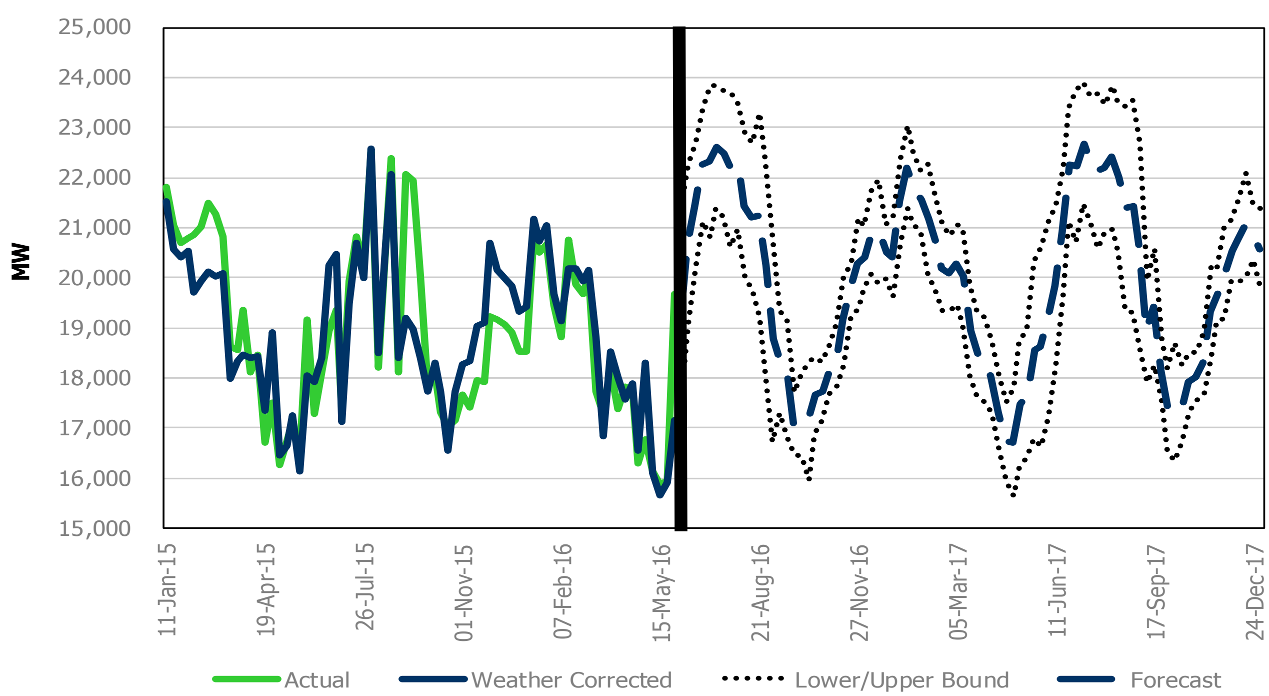


Figure 2.2: Weekly Peak Demand – History and Forecast



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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

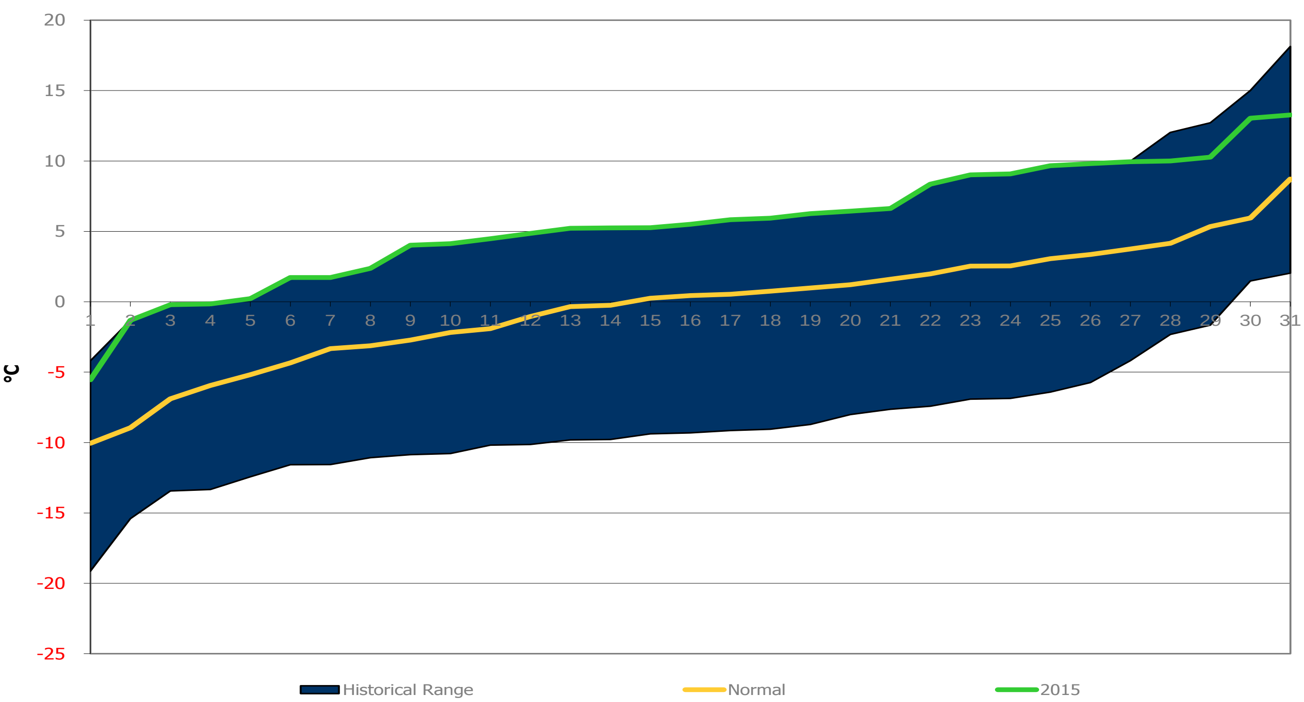
Since the last Ontario Demand document, actuals have been recorded for the period December to May. The winter of 2015-16 was very mild with December temperatures setting record highs in parts of the province. Though not as extreme, January was milder than normal and, outside of the three coldest days, February was also warmer than normal.

The spring weather was a little more mixed, with March warmer than normal, April much colder than normal and May warmer than normal. The spring peak occurred in March and was a cold-weather peak. Following is a month-by-month look at demand and weather.

December

December 2015 was the warmest December on record across most of the province. Average temperatures were over 5 °C above normal. The same held for peak temperatures. Figure 3.1 presents the ranked range of temperatures for the month, from coldest to warmest. The values for the month were consistently the mildest experienced for the month based on the history (1970 to present).

Figure 3.1: Daily Temperature - December



The month's peak demand occurred on December 1, which is very early in a month where the weather gets colder as the month progresses. At times, December peaks can be impacted by the holidays, and it could have been a factor in 2015 as the coldest temperatures fell between Christmas and New Year's Day. As it was, the peak of 19,161 MW occurred on the 15th coldest day of the month. The November peak was higher and occurred on a colder day. Not surprisingly, with the near record temperatures, the December peak was the lowest since market opening. Even after correcting for the weather the peak is still the lowest (20,155 MW).

With the milder weather, monthly energy demand was 11.3 terawatt-hours (TWh). The previous low was 12.1 TWh. After adjusting for weather, demand was 0.8 TWh higher at 12.1 TWh. This is still low by historical standards.

Minimum demand for the month was 10,811 MW, occurring during the early hours of Christmas morning. This value is once again very low as temperatures were in the double digits the prior day.

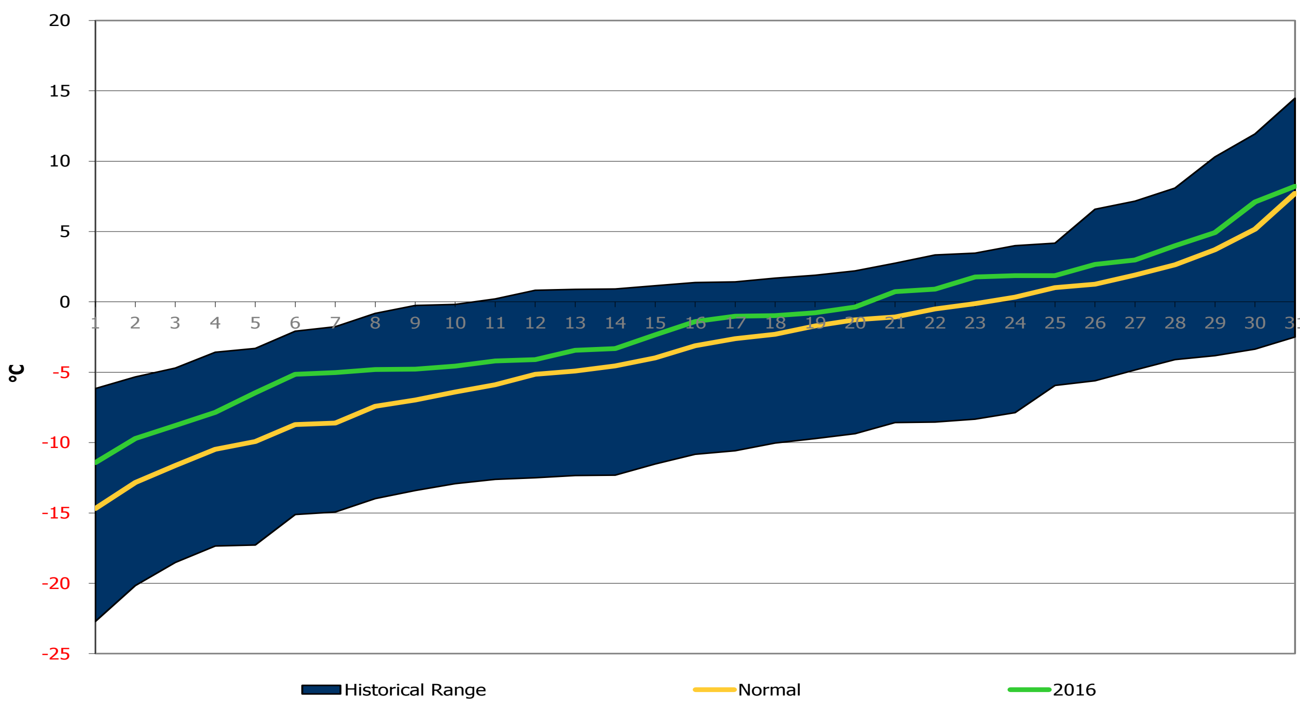
Embedded generation for the month was 443 GWh, a 2.9-percent increase over the previous December, with almost all the increase coming from solar generation.

Wholesale customers' load continued to decline, dropping by 2.5 percent compared to the previous December. There is little weather impact in this sector so the reduction is attributable to changes in the level of activity.

January

The weather turned colder in January, but it still remained warmer than normal. Figure 3.2 shows how the temperature for January 2016 stacked up against history.

Figure 3.2: Daily Temperature - January



The peak occurred on January 4, which was the coldest day of the month. It was odd though that the peak weather was a brief two-day cold spell between two warmer periods. Sustained colder weather occurred later in the month. The actual peak was 20,836 MW, and the weather-corrected peak was a slightly higher 21,158 MW. These values are low by historical standards, reflecting the on-going impact of conservation through reduced lighting loads.

Energy demand for the month was 12.3 TWh (12.6 TWh weather-corrected). Both of these figures represent the lowest January energy demand since market opening.

Minimum demand for the month was 12,116 MW, which was lower than last year but not a record. The minimum occurred at 5 a.m. on a New Year's Day.

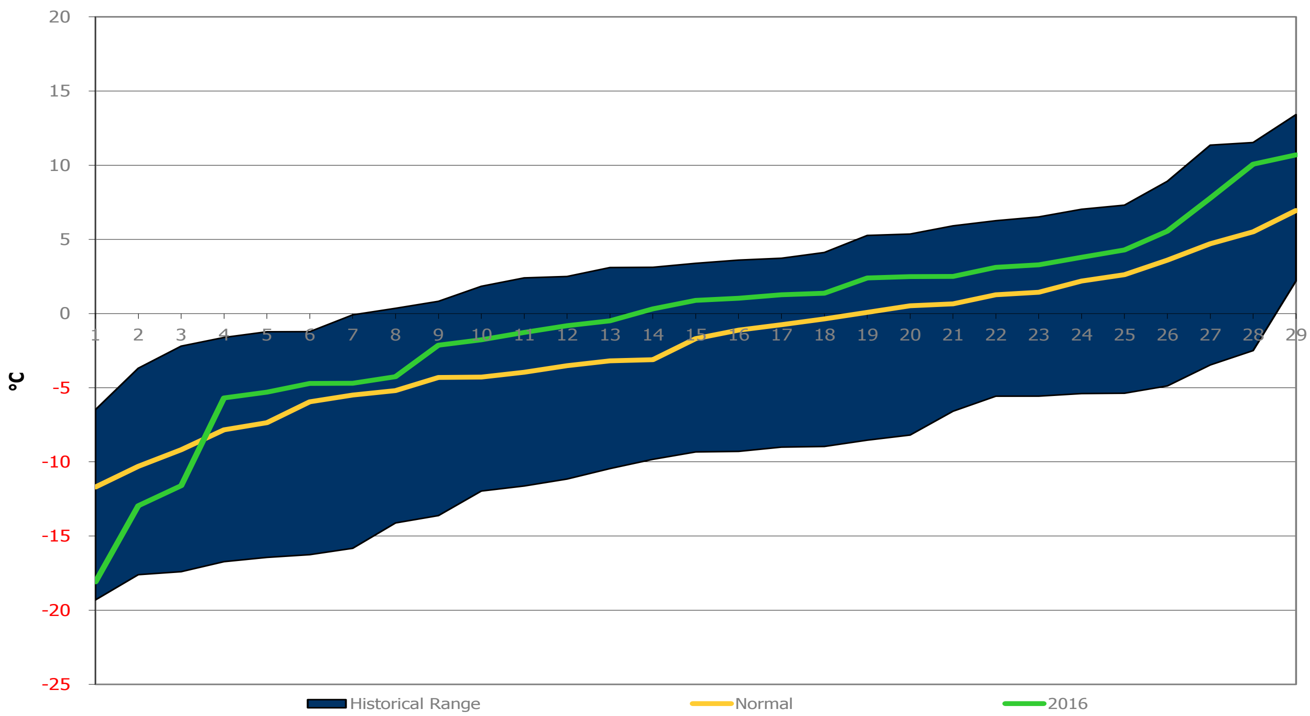
Embedded generation for the month was 476 gigawatt-hours (GWh), a 2.0-percent increase over the previous January. Solar output fell compared to the previous January, and the difference was made up with increased wind output.

Wholesale customers' consumption increased by a modest 0.9 percent compared to January 2015; this was only the second month of positive growth since October 2014.

February

February was milder than normal with the exception of the coldest three days. Figure 3.3 shows the temperature relative to history.

Figure 3.3: Daily Temperature - February



The two coldest days landed on a weekend, but the February peak occurred on third coldest day of the month, February 11. The peak was 20,766 MW and 20,195 MW weather-corrected. These numbers are consistent with the observations for February since the recession.

Energy demand for the month was 11.4 TWh (11.6 TWh weather-corrected). This is consistent with the downward trend since the recession. However, February had the benefit of an additional day due to the leap year. Once adjusted for the number of days, demand would be low by historical standards.

The minimum demand was 12,533 MW for the month and is low for a February value. The minimum occurred at 3 a.m. on a Monday.

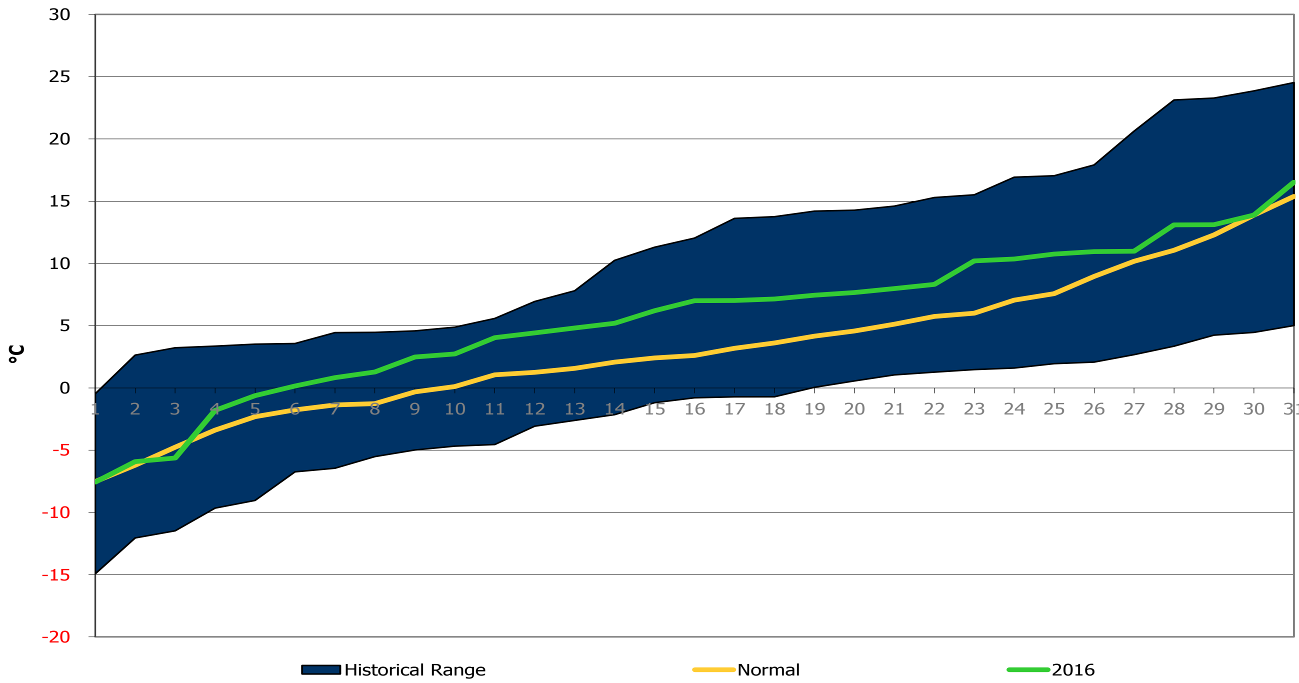
Embedded generation for the month was 482 GWh and represents a 19.3-percent increase over the previous February. Of the increase, some of the growth was due to the additional leap day, while increased wind output made up for the remainder as well as offsetting some of the reduction from embedded solar.

Wholesale customers' consumption continued to climb, increasing by 3.0 percent compared to the previous February. However, the increase was due to the additional leap day.

March

The weather for March was slightly above normal with the peak temperatures near normal. Figure 3.4 shows the March 2016 temperatures against the historical range.

Figure 3.4: Daily Temperature - March



The actual peak of 20,063 MW occurred on March 1, the coldest day of the month. In fact, it was colder at the time of the March peak than it was at the time of the December peak, and the peak demand levels reflect that. The weather-corrected peak was a very similar 20,153 MW, which is consistent with the March experience since the recession.

Energy demand for the month was 11.3 TWh and 11.6 TWh weather-corrected. Both the actual and weather-corrected energy were the lowest for March since the market opened. The low values are being impacted by the increased conservation savings and the embedded generation output.

Minimum demand for the month was 11,717 MW, which is in line with post-recession experience. The minimum occurred at 4 a.m. on a Sunday morning.

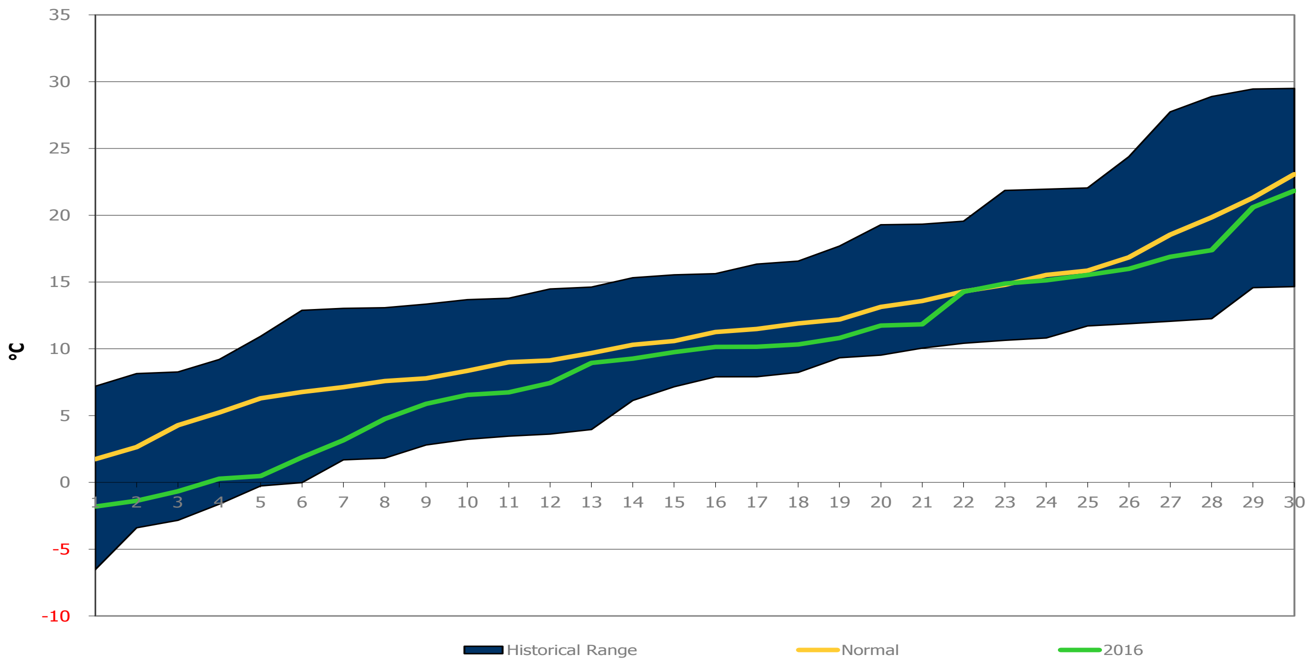
Embedded generation for the month was 536 GWh, an increase of 6.5 percent over the previous March, with the increase split evenly between increased solar and wind output.

Wholesale customers' consumption was flat in March.

April

April was colder than normal, giving people the impression of a long winter. Figure 3.5 illustrates the temperatures of April 2016 against the historical range.

Figure 3.5: Daily Temperature - April



The month's peak demand occurred on April 5, which was the coldest day of the month. Once again the April peak day was colder than the December peak day. This time, unlike March, the peak was lower than the December peak at 17,821 MW. As with previous months, this represents a record low April peak since market opening.

Energy demand for the month was 10.4 TWh, both actual and weather corrected. These values are consistent with the post-recessionary Aprils.

The minimum demand of 11,286 MW occurred at 4 a.m. on a Sunday.

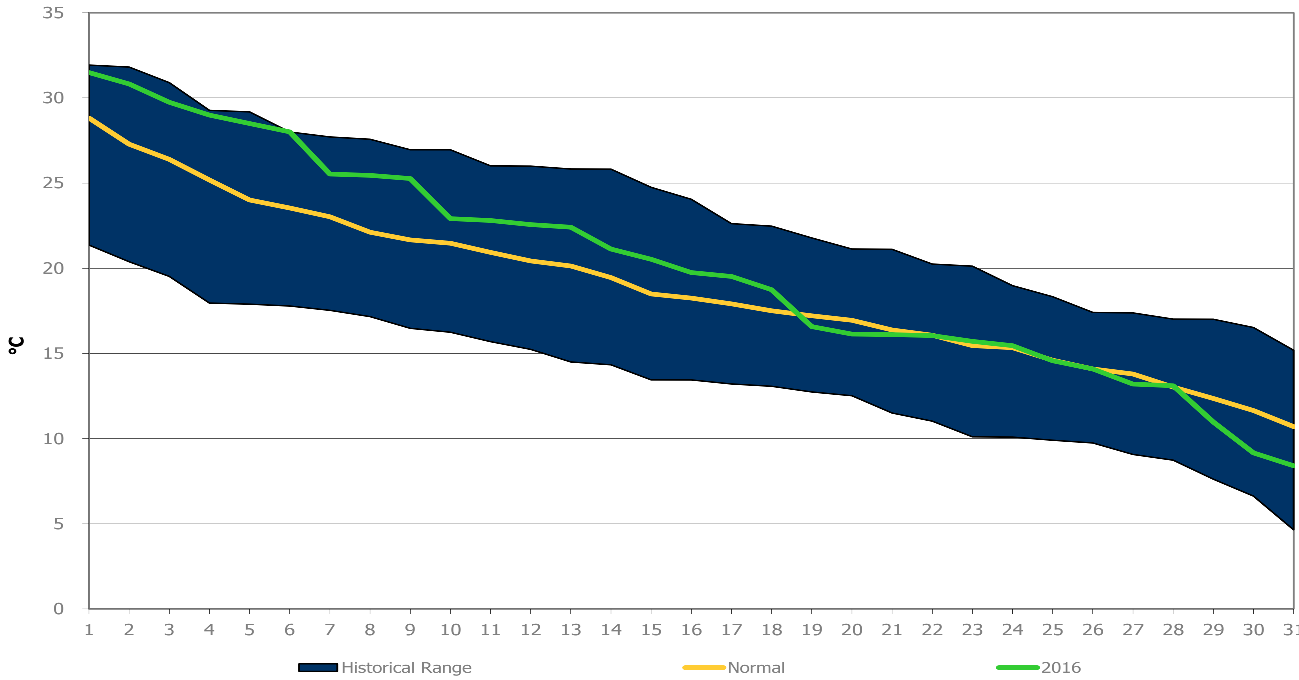
Embedded generation for the month was 669 GWh. This represents a slight 0.8-percent increase over the previous April. Solar output was down over the previous April, as embedded wind output and other embedded generation accounted for all the increase.

Wholesale customers' consumption increased 2.2 percent over the previous April. After 12 months of year-over-year declines, the wholesale load has stabilized and started to show small increases for the first time in a year, albeit by a small amount, 0.4 percent. Petroleum and chemicals were the cause behind the increase.

<u>May</u>

May started colder than normal but ended being warmer than normal. Overall the month was warmer than normal.

Figure 3.6: Daily Temperature - May



The actual peak for May was 19,885 MW occurring on Monday, May 30. It was only the 6th warmest day of the month but followed a weekend with the two hottest days of the month. The weather-corrected value was a slightly lower 19,705 MW. The weather-corrected value was the highest since May 2012 and is generally higher than the May values experienced since the recession.

The impacts of conservation and embedded generation mean that the energy demand for the month has been fairly flat since the recession but trending downward. Actual demand was 10.5 TWh and weather-corrected energy was a slightly lower 10.2 TWH. Both are historical lows for May.

Minimum demand of 10,804 MW occurred Sunday, May 8 at 4 a.m. This is a slight increase from last year and marginally better than the levels experienced during the recession.

Embedded generation topped 676 GWh for the month, which represents an increase of 25.6 percent over the previous May. Of the increase, a third was attributable to solar power, with a mix of hydro, biogas and natural gas composing the rest.

The wholesale customers' consumption fell 0.9 percent compared to the previous May. Despite big increases from the mining and cement sectors, reductions from refining and motor vehicles more than offset them.

Table 3.3.2 of the 18-Month 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 2015-2016 Weather and Demand Summary

Historical Analysis		December	January	February	March	April	May
Actual Weather	Average Temperature (°C)	6.3	-0.5	1.1	6.0	8.9	19.8
	Minimum Temperature (°C)	-5.0	-11.8	-16.9	-7.9	-2.4	7.7
	Maximum Temperature (°C)	13.7	9.6	15.5	19.5	22.9	31.1
Normal Weather	Normal Average Temperature (°C)	0.2	-3.3	-1.5	3.6	10.7	17.1
	Normal Minimum Temperature (°C)	-8.4	-13.5	-13.5	-5.5	2.8	8.7
	Normal Maximum Temperature (°C)	10.0	6.7	8.2	16.7	25.0	27.2
Actual Demand	Peak Demand (MW)	19,161	20,836	20,766	20,063	17,821	19,885
	Average Hour (MW)	15,236	16,646	16,482	15,192	14,458	14,074
	Minimum Hour (MW)	10,811	12,116	12,533	11,717	11,286	10,461
	90th Percentile (MW)	17,642	19,066	18,708	17,387	16,583	17,171
	Percent above 20,000 (MW)	0.0%	3.3%	0.7%	0.1%	0.0%	0.0%
	# of Hours Above 20,000 (MW)	0	25	5	1	0	0
	Energy Demand (GWh)	11,335	12,385	11,472	11,303	10,410	10,471
Weather Corrected Demand	Peak Demand (MW)	20,155	21,158	20,195	20,153	18,292	19,705
	Energy Demand (GWh)	12,083	12,620	11,593	11,532	10,440	10,225
Forecast Demand	Peak Demand (MW)	21,160	22,360	20,985	20,075	17,405	19,236
	Energy Demand (GWh)	12,611	12,982	11,807	11,759	10,310	10,530

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, winter (December, January and February) and spring (March, April and May).

The weather over the winter was much milder than normal. As such, overall electricity demand was down 6.4 percent compared to the previous winter. After adjusting for the mild weather, the decline was a more moderate 1.0 percent. However, this still does not account for the extra day. Adjusting for the leap year means that the weather-corrected winter demand declined by 2.1 percent over the previous winter.

Distributors' loads have declined by 7.5 percent over the winter compared to last winter. After making the weather and leap year adjustment, that decline is a more modest 2.4 percent. This reduction is a result of growth in embedded generation output, conservation savings and economic structural change. Over the course of the winter, embedded generation was 1.4 TWh, an increase of 7.7 percent over the previous year.

For the winter months, wholesale loads showed a small increase of 0.4 percent compared to the previous winter. However, that becomes a small decrease of 0.7 percent once adjusted for the additional leap day. Still, it represents a significant change from 2015, when 11 of the 12 months experienced year-over-year declines.

For the spring, demand was 2.5 percent lower than the previous year but only 1.0 percent lower after adjusting for weather. The distributor loads showed an actual decline of 2.7 percent and a 1.0-percent decline after correcting for weather.

Wholesale customers' loads increased by 0.4 percent over the previous spring. The increases were driven by the steel and cement industries.

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. Annual embedded generation topped 6.2 TWh in 2015, up from 2.0 TWh in 2009. Moving forward, the embedded generation component will continue to grow as more renewable energy comes into commercial operation.

For the six months from December to May, distributors' loads declined by 5.3 percent compared to the same six-month period a year earlier. Once you adjust for weather and add back the embedded generation, the decline is 0.6 percent, which reflects the impact of conservation savings.

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

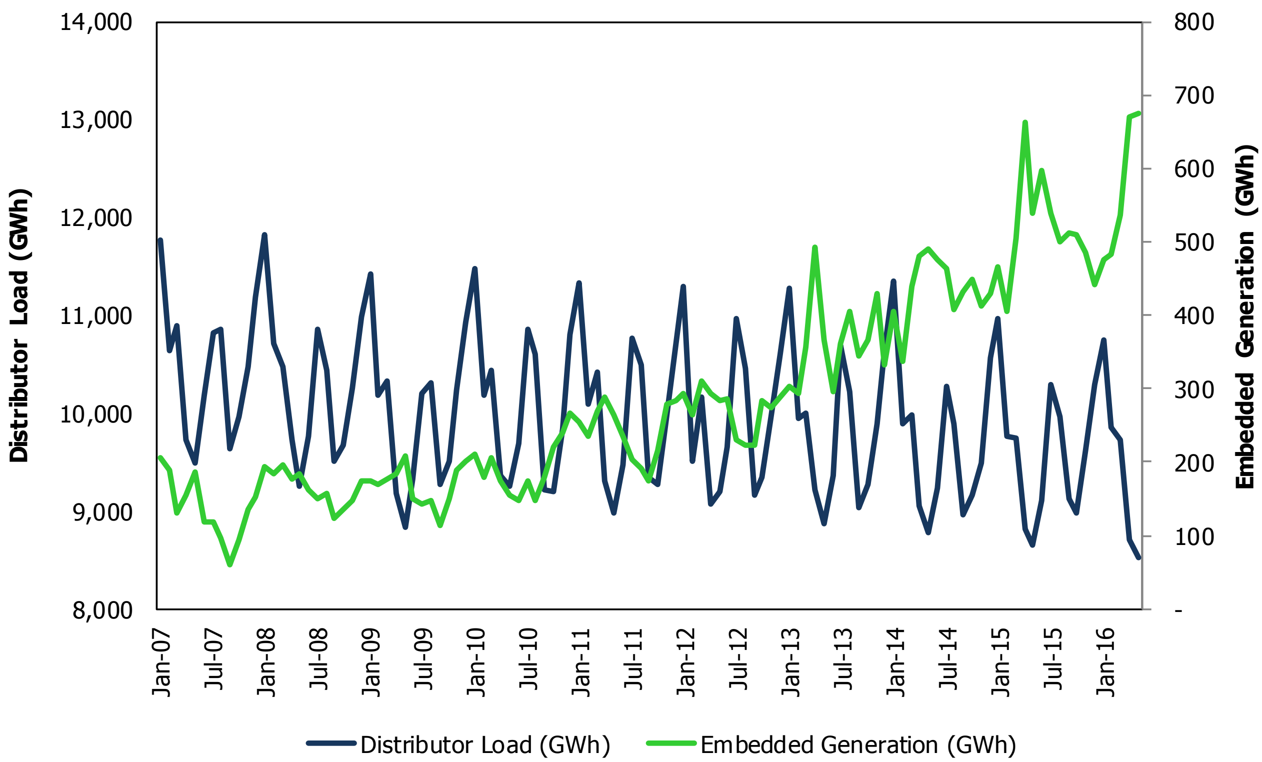


Figure 3.8 shows the year-over-year change in wholesale customers' average hourly consumption. The graph illustrates the impact of the recession, modest recovery and erosion of the past year. The graph illustrates the declines through 2015 and the return to modest growth with the start of 2016.

Figure 3.9 shows the wholesale customers' average hourly load by industry segment for the past six months (December to May) compared to the same six months prior to the recession (December 2007 to May 2008) and a year ago. Petroleum and Other are the only sectors that have seen an increase over both the pre-recessionary period to last year; both increases are very small.

The sectors have been fairly consistent, with the exception of the large declines immediately after the recession in Pulp & Paper and Iron & Steel. At market opening, Pulp & Paper was the largest industrial segment with an average hourly load of 736 MW. Now that segment ranks third at 233 MW. Mining is now the largest industrial segment with an average hourly load of 560 MW, up from 493 MW at market opening. The changing industrial structure is due to a variety of causes. Some changes are sector specific – the impact of the decline in demand for newsprints on Pulp & Paper – while other changes are broad-based – such as the appreciation of the Canadian dollar from 2004 through to 2014. Generally, loads were declining over the 2004-2008 timeframe as the Canadian dollar appreciated. In 2009, the financial crisis and ensuing recession led to a sharp decline in wholesale load as industry re-structured and scaled back production. Wholesale loads declined by 24 percent in 2009. Loads rebounded in 2010 and have averaged annual growth of 1.5 percent since the recession, though they dropped again in 2015.

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

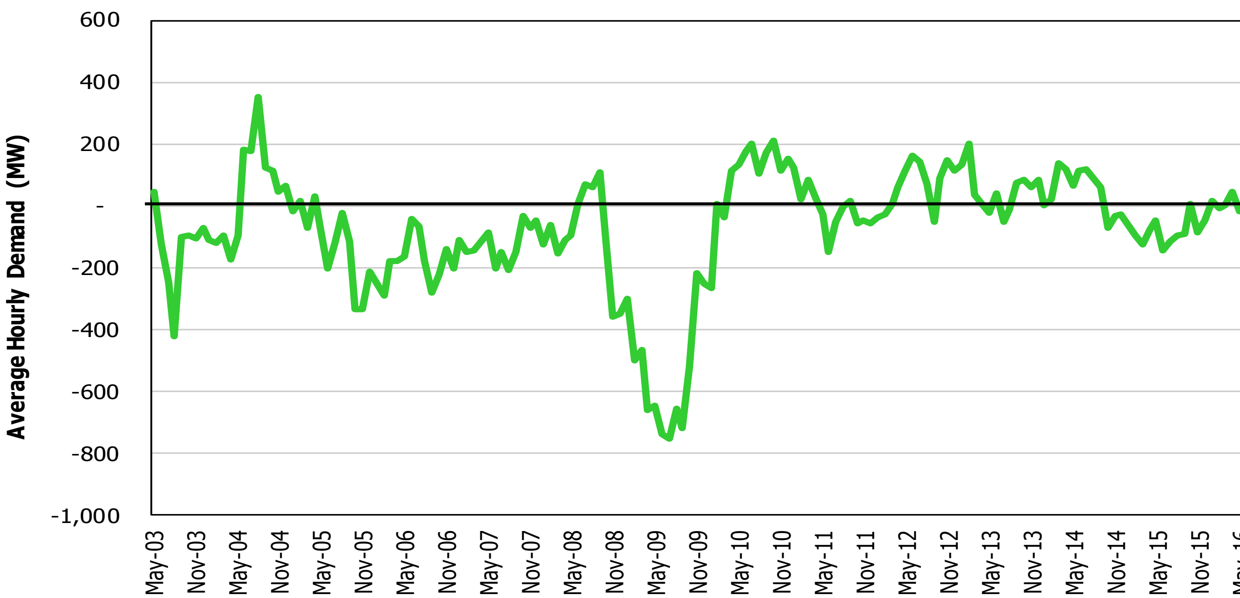


Figure 3.9: Wholesale Customers' Average Hourly Consumption by Industry Segment

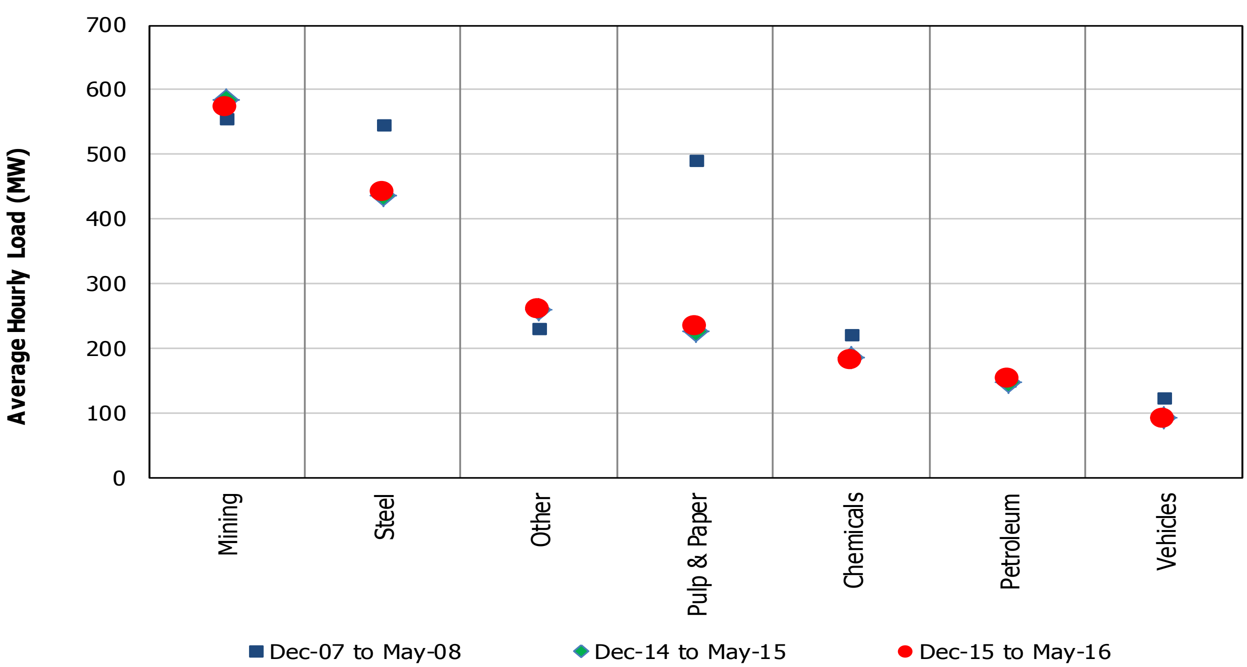


Table 3.2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week and notes any item of significance for the week. If the weather-corrected demand is greater than the actual demand, it means that the actual weather was milder than normal. Additional history is available in the [18-Month 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
49	06-Dec-15	01-Dec-15	2,636	2,796	
50	13-Dec-15	07-Dec-15	2,577	2,737	
51	20-Dec-15	15-Dec-15	2,641	2,810	
52	27-Dec-15	21-Dec-15	2,398	2,559	Christmas & Boxing Day
53	03-Jan-16	03-Jan-16	2,536	2,653	New Year's Day
1	10-Jan-16	04-Jan-16	2,793	2,845	
2	17-Jan-16	11-Jan-16	2,880	2,945	
3	24-Jan-16	19-Jan-16	2,914	2,971	
4	31-Jan-16	29-Jan-16	2,737	2,783	
5	07-Feb-16	04-Feb-16	2,658	2,705	
6	14-Feb-16	11-Feb-16	2,926	2,891	
7	21-Feb-16	17-Feb-16	2,771	2,818	Family Day
8	28-Feb-16	24-Feb-16	2,729	2,786	
9	06-Mar-16	01-Mar-16	2,775	2,777	
10	13-Mar-16	10-Mar-16	2,478	2,725	
11	20-Mar-16	15-Mar-16	2,490	2,359	
12	27-Mar-16	21-Mar-16	2,513	2,539	Good Friday
13	03-Apr-16	29-Mar-16	2,474	2,570	Easter Monday
14	10-Apr-16	05-Apr-16	2,601	2,511	
15	17-Apr-16	12-Apr-16	2,422	2,491	
16	24-Apr-16	19-Apr-16	2,301	2,340	
17	01-May-16	25-Apr-16	2,362	2,334	
18	08-May-16	02-May-16	2,270	2,291	
19	15-May-16	12-May-16	2,264	2,228	
20	22-May-16	19-May-16	2,248	2,246	
21	29-May-16	27-May-16	2,579	2,353	Victoria Day

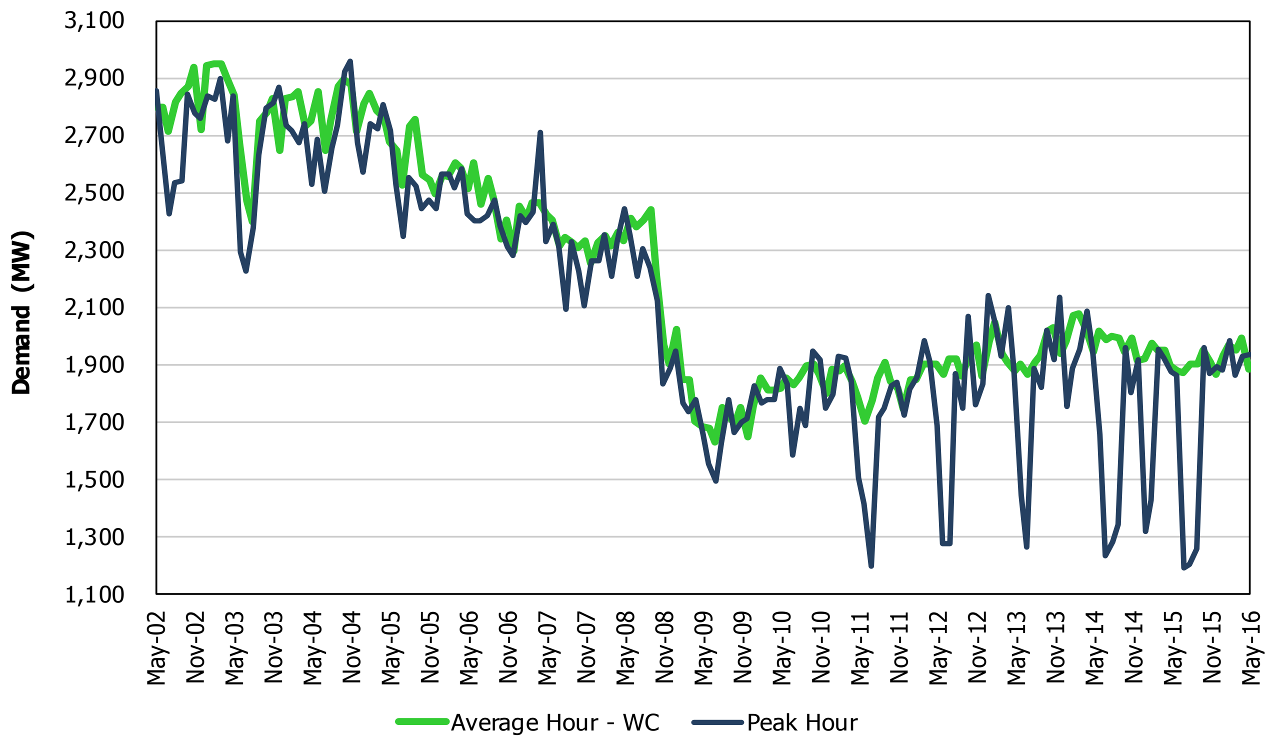
3.3 Historical Peak Demand

Peak demands are weather-driven, weekday events. 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 20,836 MW, which is lower than last winter's peak (21,814 MW). The weather was significantly colder during the previous winter. As well, the ICI was available last winter, which would have a further downward impact on previous winter's peak. Setting the ICI impacts aside, the difference came from the weather.

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. 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 2014, the program was expanded to include customers with a peak load of 3 MW or higher. Previously, the program had a threshold of 5 MW or higher.

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 than 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 dispel the accumulated heat. Now the embedded solar is "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 and the winter of 2015. 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 and 2015. 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. 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

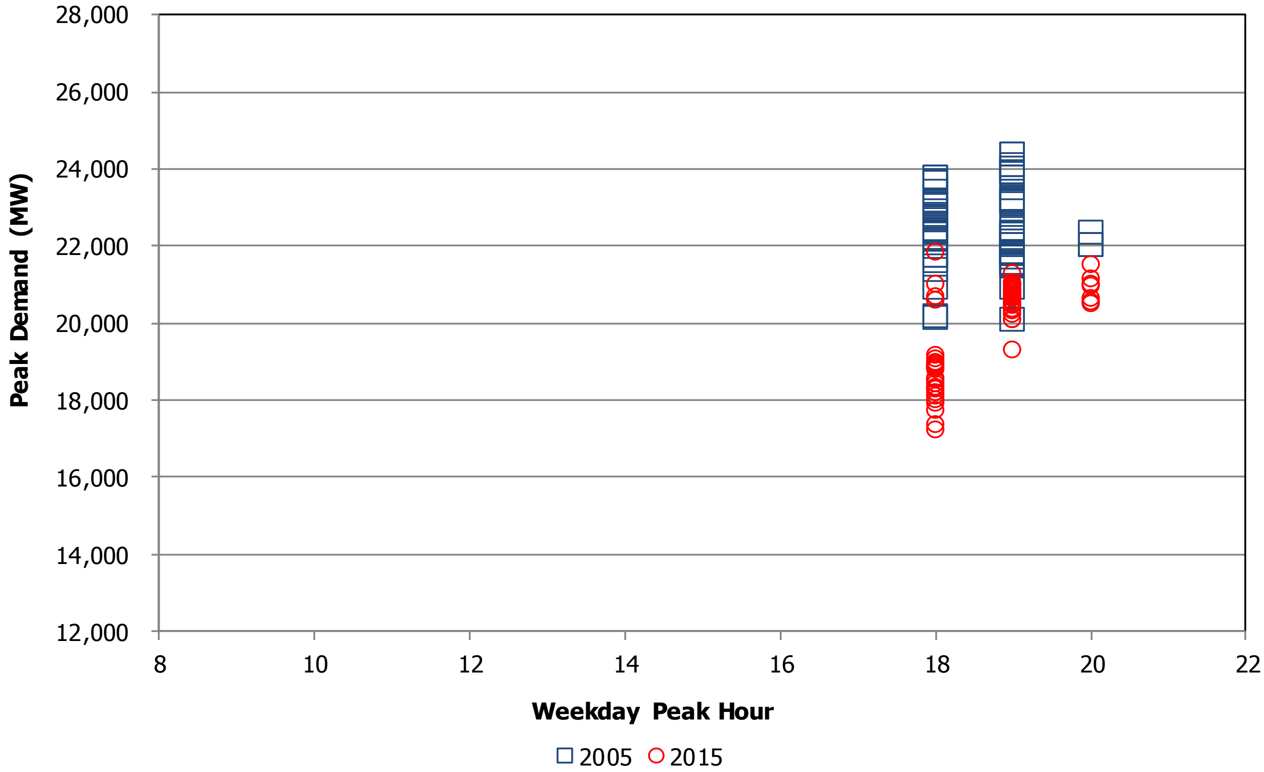
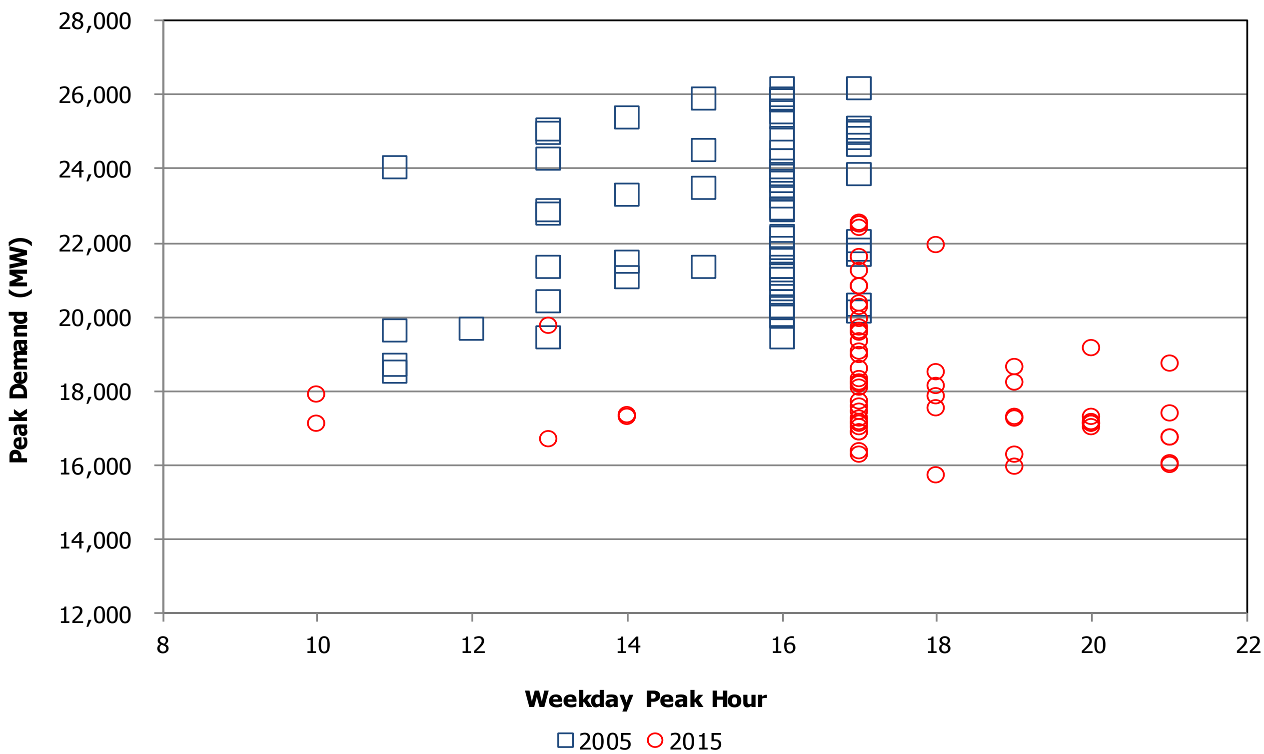


Figure 3.12: Seasonal Weekday Peak Hour Distribution – Summer



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 summer 2014, winter 2015, summer 2015 and winter 2016 peaks. These show the actual results and are not adjusted for weather. The illustration shows that there are a number of factors working to reduce the seasonal grid peaks and that they vary in size depending on the season and peak itself. The figure shows a reconstituted peak demand -- the peak demand that would have been had it not been for a variety of load modifiers. The interesting aspect is that the winter peak of 2014-15 was the first winter peak to be impacted by the ICI.

Figure 3.13: Anatomy of Seasonal Peaks

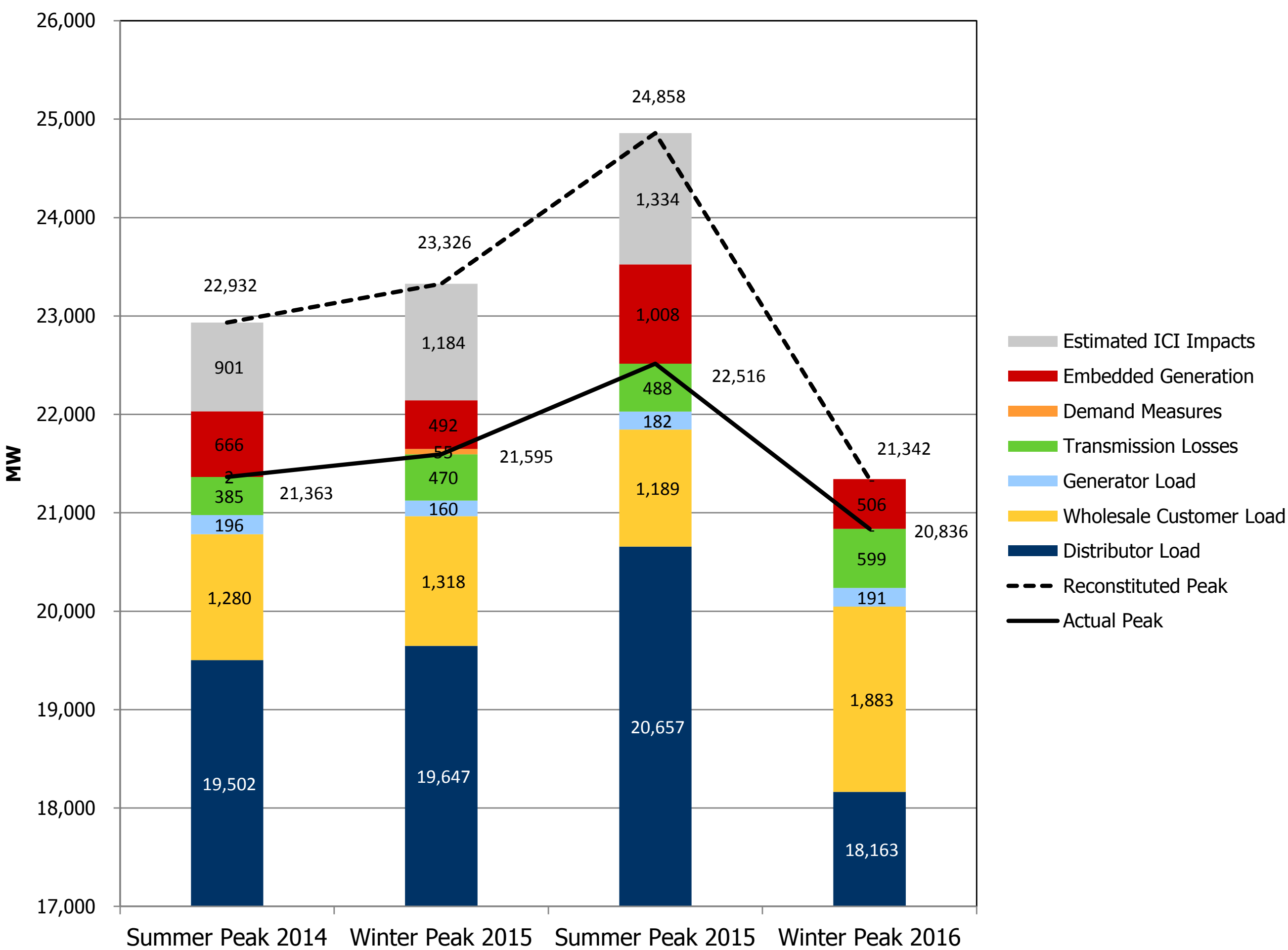


Table 3.3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3.3: Historic Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
49	06-Dec-15	01-Dec-15	19,161	20,155	6.8
50	13-Dec-15	07-Dec-15	19,064	19,998	5.4
51	20-Dec-15	15-Dec-15	18,909	19,820	8.6
52	27-Dec-15	21-Dec-15	18,527	19,321	6.6
53	03-Jan-16	03-Jan-16	18,512	19,423	1.6
1	10-Jan-16	04-Jan-16	20,836	21,158	-11.8
2	17-Jan-16	11-Jan-16	20,494	20,727	-6.6
3	24-Jan-16	19-Jan-16	20,660	21,056	-4.3
4	31-Jan-16	29-Jan-16	19,439	19,666	-5.1
5	07-Feb-16	04-Feb-16	18,818	19,112	2.9
6	14-Feb-16	11-Feb-16	20,766	20,166	-10.0
7	21-Feb-16	17-Feb-16	19,863	20,195	-1.4
8	28-Feb-16	24-Feb-16	19,675	19,930	1.7
9	06-Mar-16	01-Mar-16	20,063	20,153	-7.9
10	13-Mar-16	10-Mar-16	17,715	18,817	10.2
11	20-Mar-16	15-Mar-16	17,267	16,816	9.3
12	27-Mar-16	21-Mar-16	18,168	18,517	3.5
13	03-Apr-16	29-Mar-16	17,381	18,005	7.2
14	10-Apr-16	05-Apr-16	17,821	17,557	0.6
15	17-Apr-16	12-Apr-16	17,743	17,879	6.7
16	24-Apr-16	19-Apr-16	16,283	16,549	15.8
17	01-May-16	25-Apr-16	16,774	18,292	7.4
18	08-May-16	02-May-16	16,116	16,101	12.0
19	15-May-16	12-May-16	15,884	15,658	20.5
20	22-May-16	19-May-16	15,949	15,892	19.7
21	29-May-16	27-May-16	19,681	17,141	28.9

3.4 Load Duration Curves

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

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 remains low by historical standards.

Figure 3.14: Spring Load Duration Curve

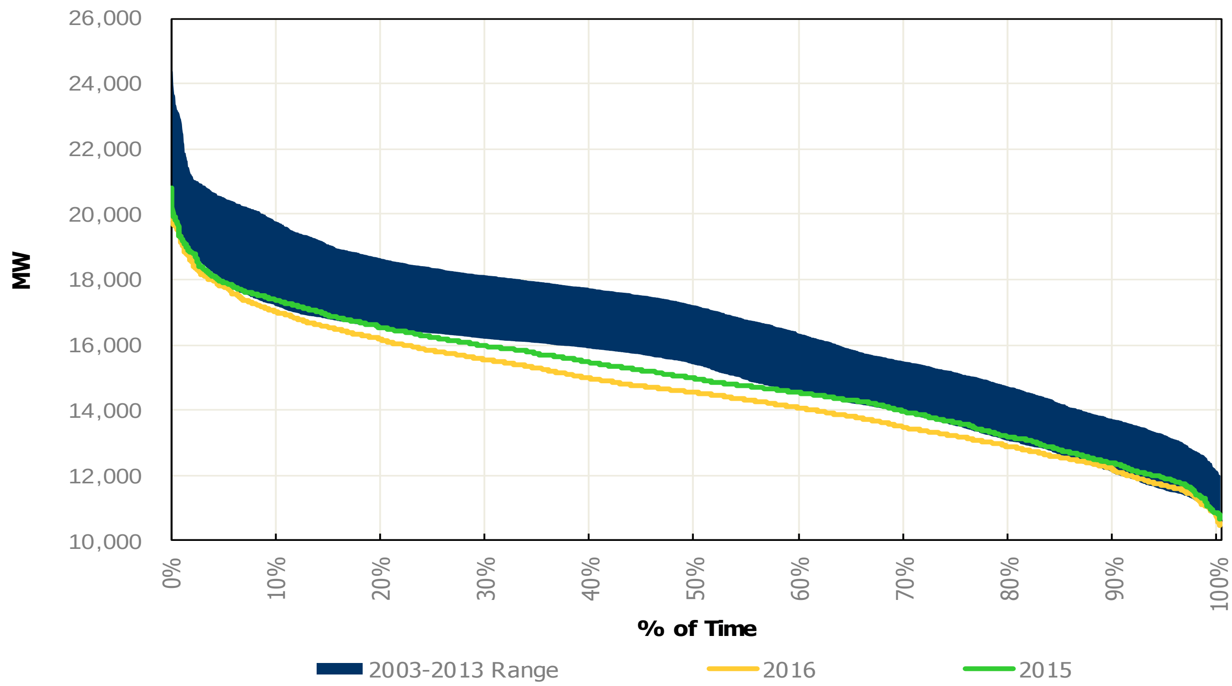


Figure 3.15: Winter Load Duration Curve

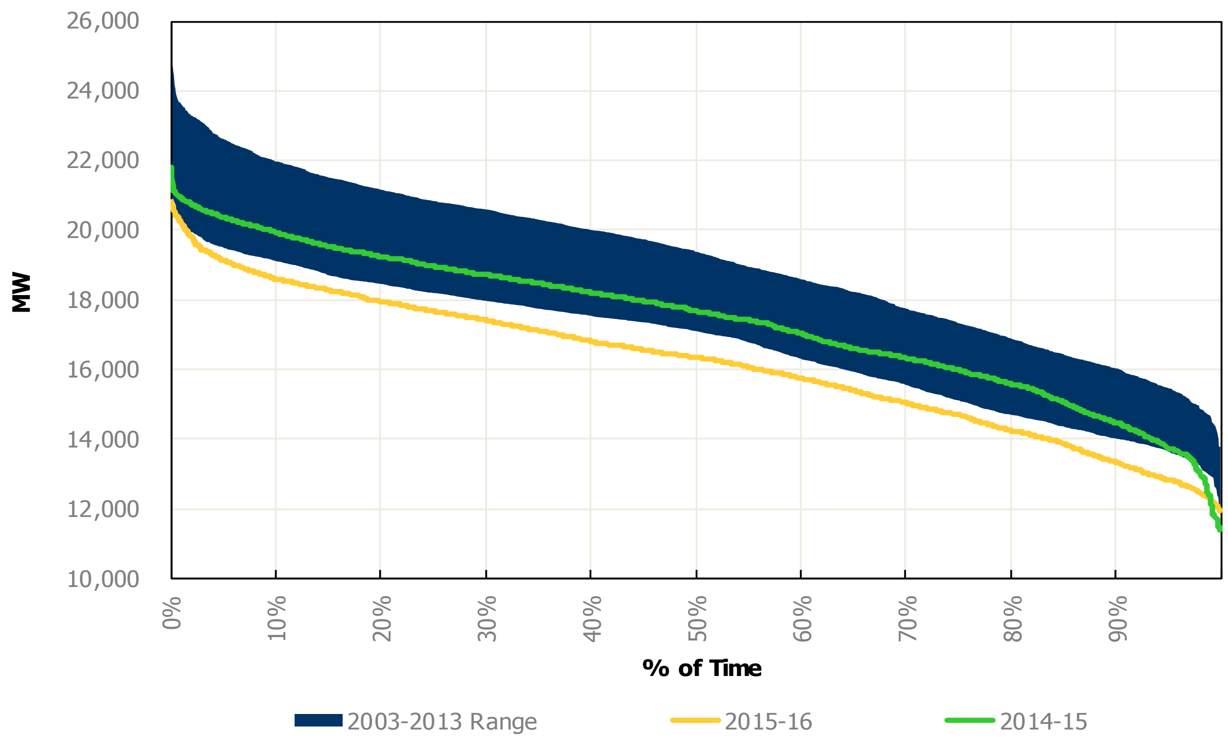


Figure 3.16: Fall Load Duration Curve

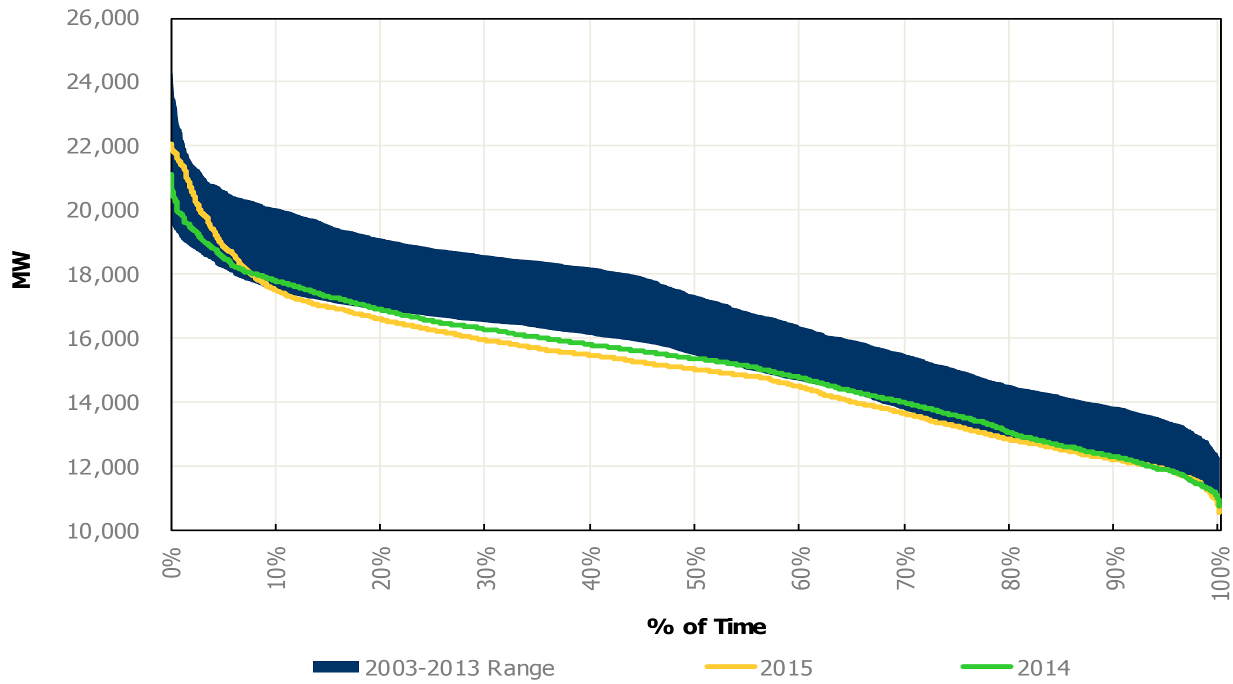
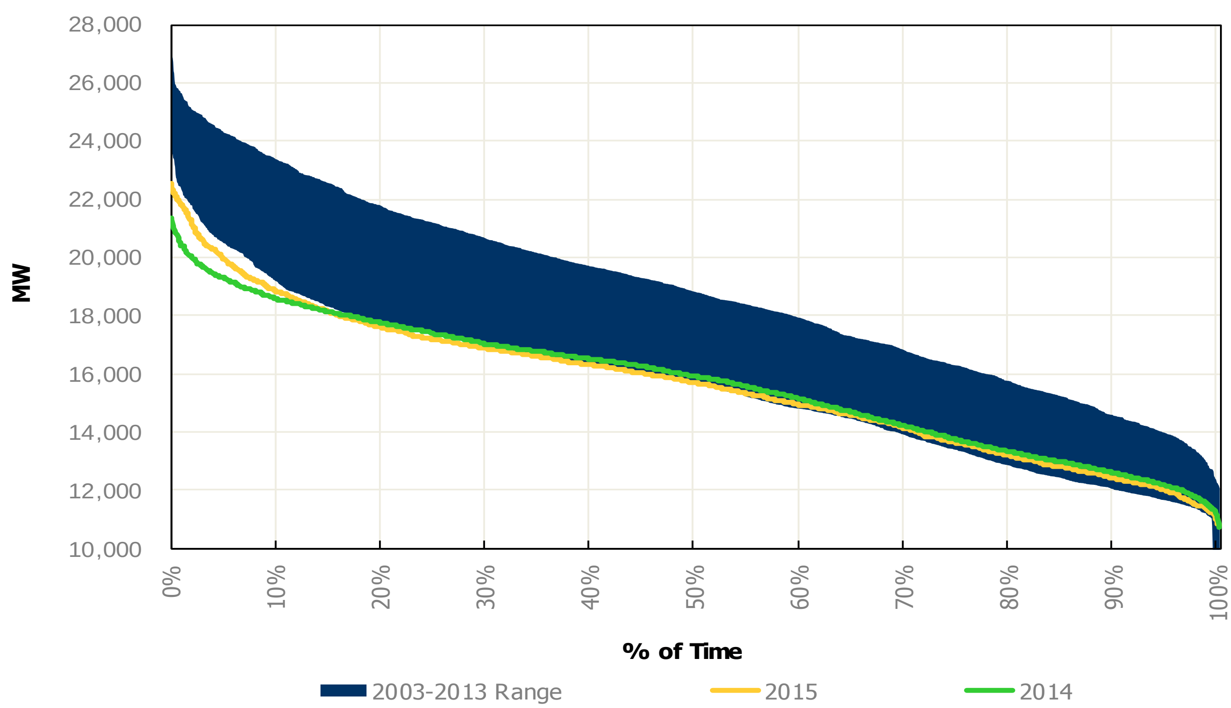


Figure 3.17: Summer Load Duration Curve



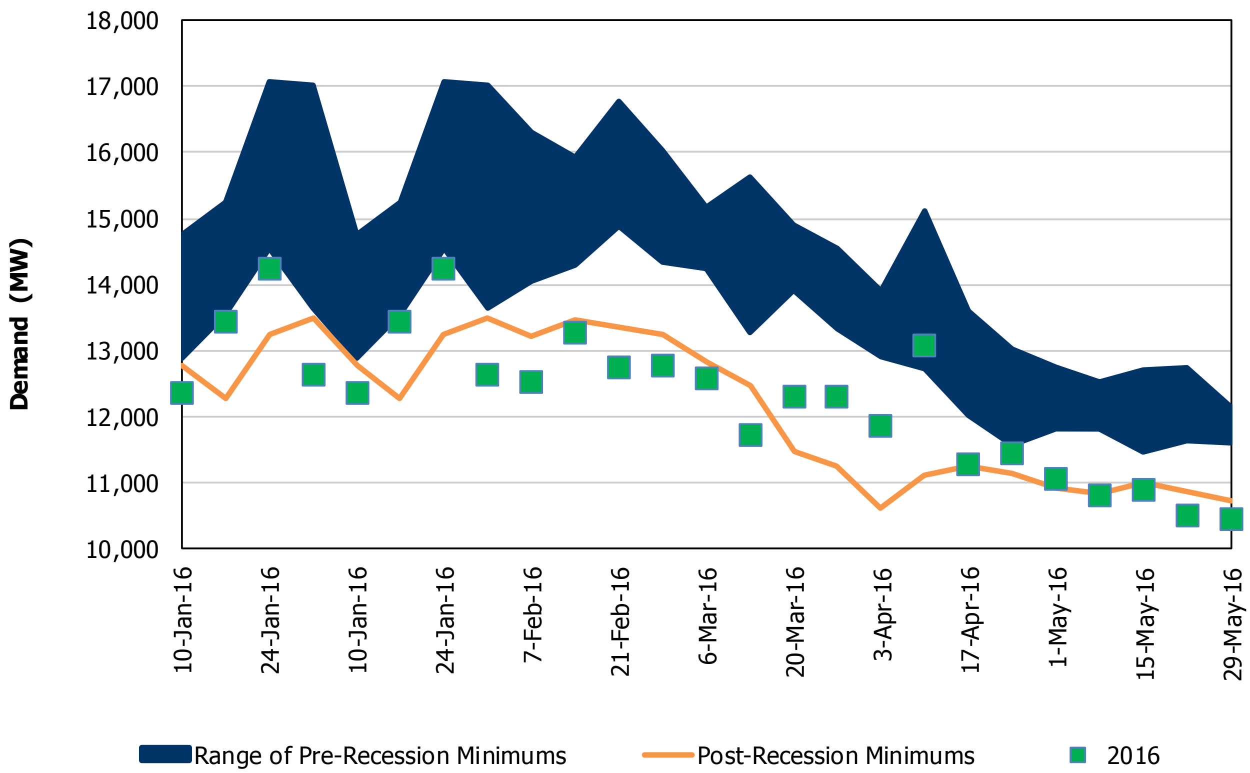
3.5 Historical Minimum Demand

Like peak demands, the minimums are driven by weather, calendar and economic effects. Which of the drivers is most important varies throughout the seasons. 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 early 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 band represents the range of values for the years 2002 - 2008. The line shows the lowest weekly minimums post-recession, and the squares represent the weekly minimums for the past six months.

The minimums of the past six months reflect the weather. Numerous times in 2016 the weekly minimums were reaching new lows. This is due to a combination of impacts – embedded generation, conservation, mild weather and the level of overnight economic activity. Most of the weekly minimums come on the weekend or holidays when the level of economic activity is lower.

Figure 3.18: 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/Documents/marketReports/Methodology_RTAA_2016jun.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, sunrise and sunset – 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.

Despite strong economic fundamentals – low interest rates, a strong financial sector and a rich resource base -- Canada has not experienced strong growth in the post-recession recovery period. Much of that can be explained by the overall global situation. Since Canada is trade dependent, sluggish growth throughout industrialized countries was felt here in Canada. The developing nations -- China in particular -- were experiencing strong growth but are generally not markets for Canada's finished goods. They are consumers of commodities and their strong performance had a positive impact on the resource sector.

The recent decline in oil prices has had two significant impacts for Canada. First has been the direct impact on the oil-producing regions of Canada, where jobs have been lost and investment significantly scaled back. The second impact has been a weakening of the Canadian dollar. The oil price collapse and stronger U.S. growth has led to a significant change in the exchange rate with Canada's major trading partner. The dollar is the lowest it has been in well over 10 years.

This economic climate bodes well for central Canada's export-oriented manufacturing sector. Strong U.S. growth means there is a market for Canada's goods. Lower commodity prices mean the cost of inputs has declined. Finally, a lower dollar means exports will be more competitively priced. All this lays the ground work for improved economic activity in Ontario. However, that stronger growth has yet to be realized.

Lower commodity prices have had a negative impact on the resource sector. Despite this, Ontario's resource sector employment hasn't seen a decline. Conversely, manufacturing employment has started to increase after years of decline. The start to 2016 has seen stronger growth numbers and there are a number of positive signs. The coming months will reveal how strong and broad-based this economic growth is.

There are a number of downside risks to the economic outlook, including geopolitical, the impacts of the Trans-Pacific Partnership and forthcoming environmental initiatives. The impacts of the latter two will be seen as more details are provided.

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	1.60
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 (f)	7,002	1.1	69.7	2.1	1.392	1.25
2017 (f)	7,079	1.1	66.5	-4.6	1.408	1.18

In previous reports, 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.

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. Since then, however, growth has been an "either/or" experience with either the GTA or the rest of the province dominating. The start of 2016 has shown only a hint of more balanced job growth between the two sub-provincial areas. If growth is to be sustained, more jobs will have to be generated outside of the GTA.

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. Though not really strong, the last year has seen increases across the broad sectors of the economy. This is encouraging, as the manufacturing sector in particular, and the goods-producing sector in general, have been in decline since before the recession. For the first five months of 2016, the manufacturing sector is up 16,000 jobs over the same period a year ago.

Figure 4.1: Zonal Employment Growth

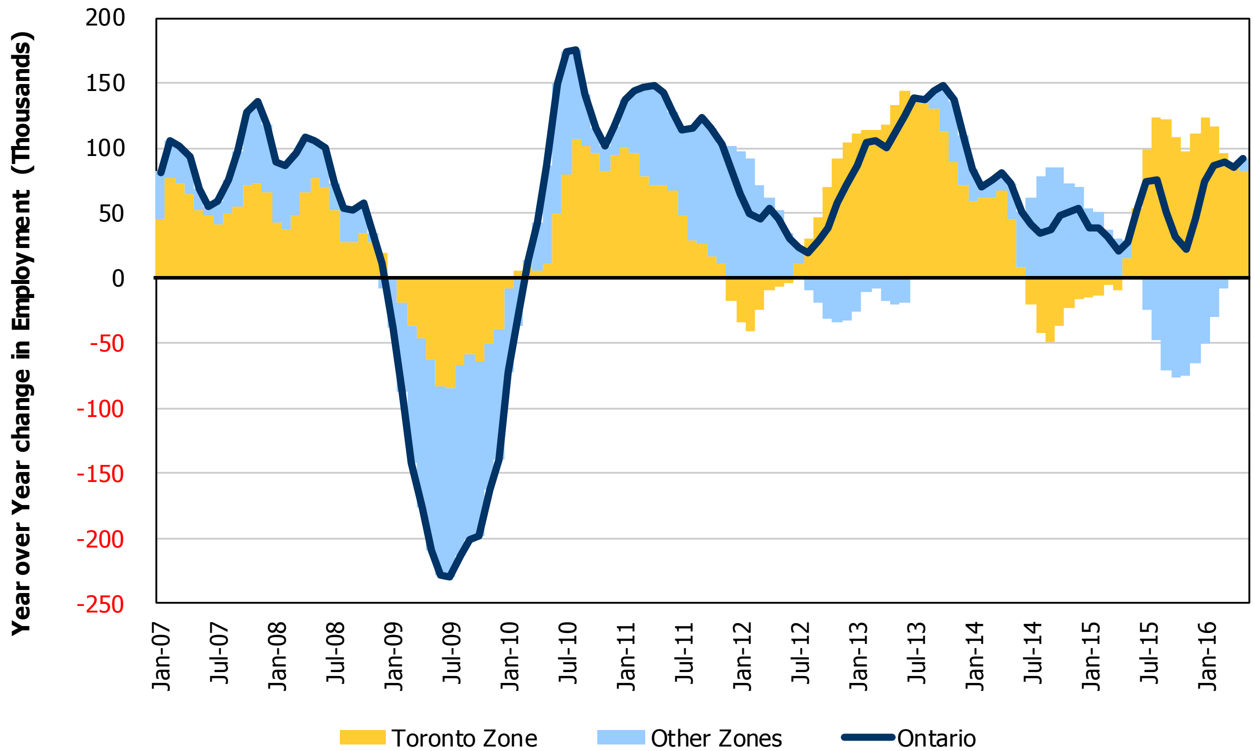
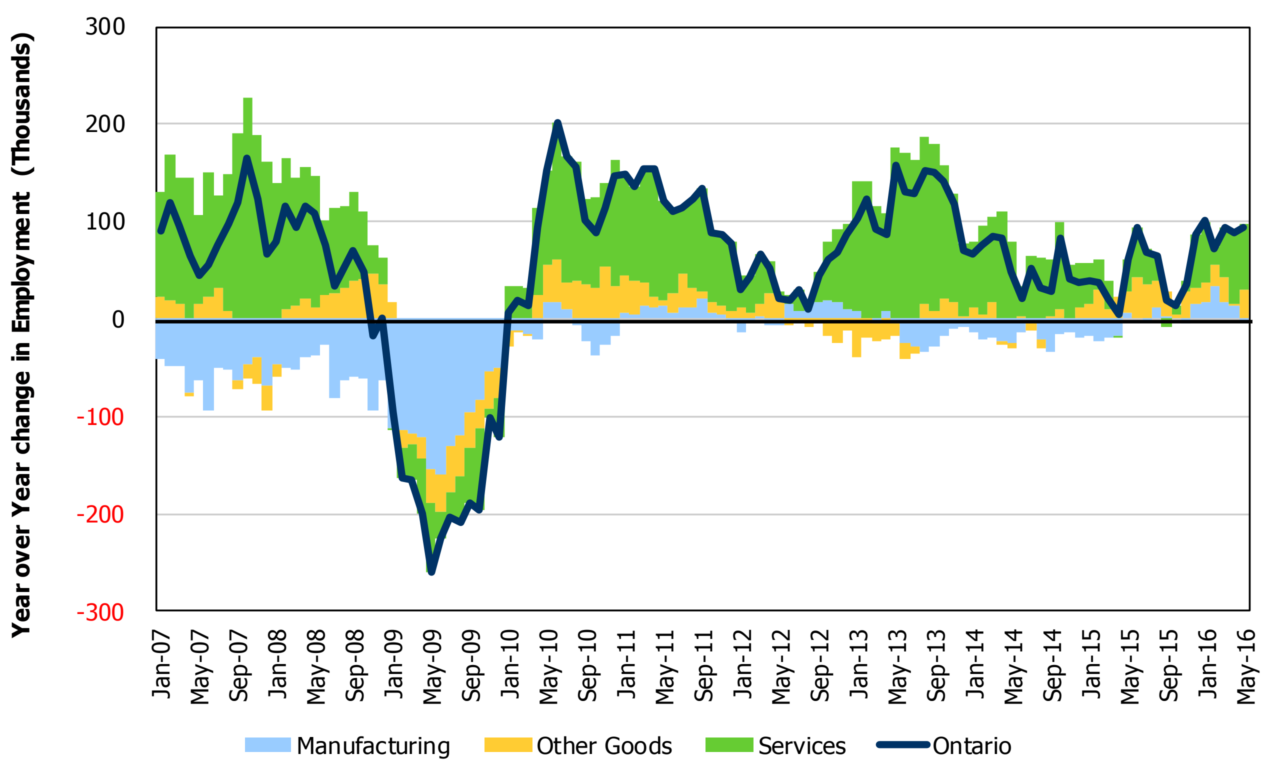


Figure 4.2: Composition of Ontario's Employment Growth



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. 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, demand response programs and the peaksaver PLUS program. 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 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 in 2014 to include customers who have a peak demand of greater than 3 MW. 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 1,075 MW for the five peak days in 2015.

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). It also includes 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

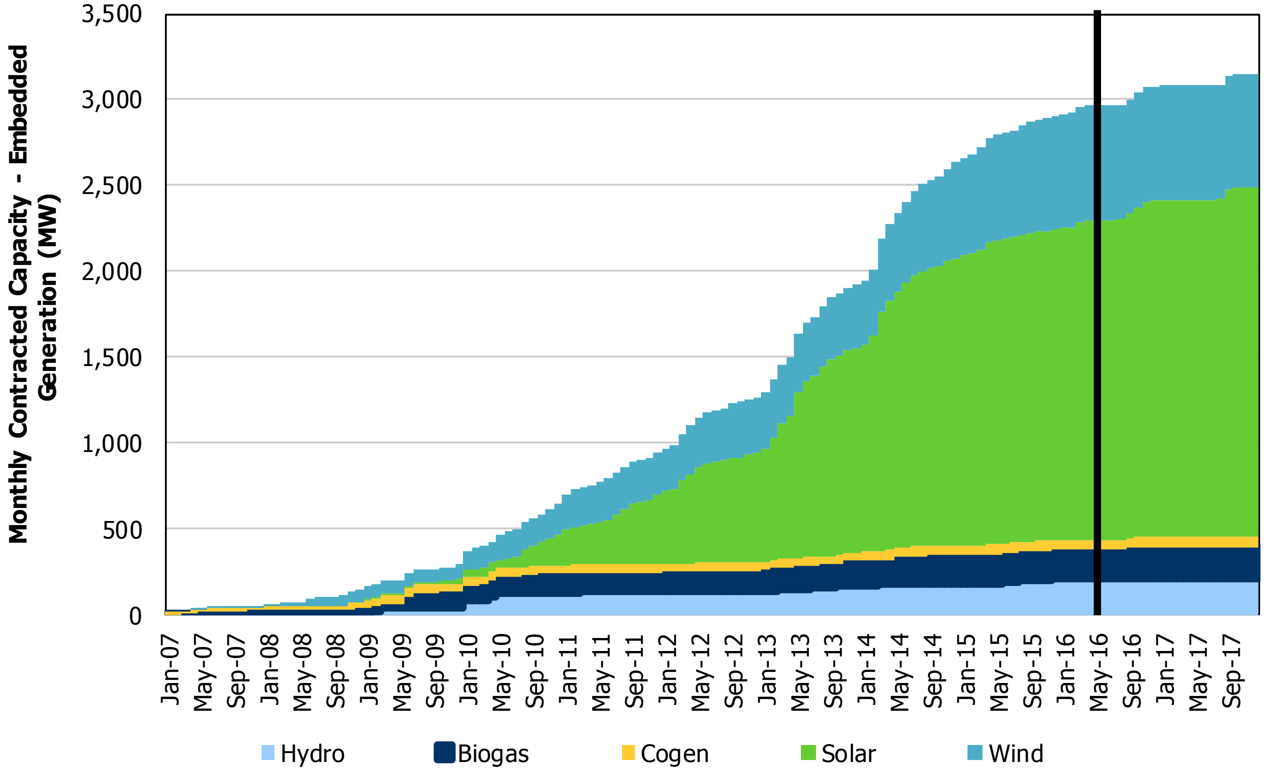


Table 4.2: Embedded Capacity

Month	Estimate of Contracted Embedded Generation Capacity (MW)					
	Biogas	Cogeneration	Solar	Hydro	Wind	Total
Jun-07	16	18	0	5	7	46
Jun-08	23	21	0	7	26	77
Jun-09	27	49	10	41	74	202
Jun-10	97	49	52	127	160	485
Jun-11	111	49	258	134	241	793
Jun-12	117	49	583	138	298	1,185
Jun-13	133	49	1,011	152	335	1,680
Jun-14	164	55	1,519	179	468	2,384
Jun-15	169	59	1,784	189	611	2,813
Jun-16	170	60	1,866	208	667	2,971
Jun-17	187	60	1,975	208	667	3,097

Over the course of the 18-month forecast, the amount of embedded solar installed capacity will range from over 1,800 MW to just over 2,000 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. Table 4.3 shows the monthly average forecasted capacity factor (%) of embedded solar at the time of the weekday peak hour. Since winter peaks occur after sunset, the average contribution is zero for the winter months. 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. Note that the solar capacity contribution for grid-connected solar is calculated differently than for embedded solar due to the analytical requirements.

Table 4.3: Forecasted Embedded Solar Capacity for the Weekday Peak Hour

Monthly Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Forecasted Embedded Solar Capacity Factor (%) at Weekday Peak Hour	0.0%	0.0%	0.0%	0.0%	5.7%	20.0%	22.5%	17.3%	0.0%	0.0%	0.0%	0.0%

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