18-Month Outlook

An Assessment of the Reliability and Operability of the Ontario Electricity System

Ontario Demand Forecast

JUNE 22, 2015

Independent Electricity System Operator

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 2015 to December 2016 and supersedes the previous forecast released in March 2015.

Economic Outlook

The economic outlook has been fairly consistent since the end of the 2009-10 recession. Canada has strong domestic fundamentals: we are resource rich, have low interest rates and a healthy financial sector. Despite this, we are also very dependent on trade and are not immune to the state of the global economy. This was reflected in our recent economic growth, which was high for the developed world but not high enough to significantly reduce unemployment, lower personal debt and instill confidence in consumers and businesses. In terms of trade, Ontario is particularly impacted by the state of the U.S. economy, which is a major consumer of its goods.

That is why the recent economic developments have led many financial analysts to be bullish on Ontario's growth prospects. A lower dollar, lower energy prices and a stronger U.S. economy are all favourable for the province's manufacturing sector. Once these recent developments establish themselves as the new business environment, then industry will benefit from increased demand and price competitiveness. This may help central Canada lead the nation in growth.

Downside risk still exists in geopolitics, debt issues and higher energy prices. However, this is the most optimistic outlook for Ontario in recent years.

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 2.8% over the same period a year earlier. The previous winter had an extremely cold March while this past winter had an extremely cold February. Therefore the weather corrected demand had a very similar 2.7% decline.

For the past six months, distributor loads have dropped by 1.9% 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.

Over the same period, wholesale customers' consumption has dropped, reversing a trend of year over year increases for 13 consecutive months. For the six months, wholesale loads have dropped by 3.6% compared to a year ago.

The 2014-15 winter peak demand occurred on January 7th, which was part of the cold snap that started 2015. The afternoon high was -15.7°C (Toronto). Ironically, the previous winters' peak also occurred on January 7th under similar weather conditions. However this year's peak was 21,814 MW compared to 22,744 MW in January 2014. The reason the peak was lower despite similar weather conditions is attributed to the Industrial Conservation Initiative (ICI). With the mild summer of 2014, this past winter's peak became an ICI day accounting for the most of the decline in the winter peak hour demand.

Throughout the spring, the minimum demands have followed along the lows established since the recession. This is consistent with the lower wholesale customer load experienced during the same timeframe.

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 with the result of reducing demand. Conversely, demand response programs are included in our 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 decline 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, ICI impacts and growth in solar embedded generation.

Grid supplied energy demand is expected to show a small reduction in 2015 before increasing in 2016. The growth rate in 2016 will be exaggerated by 0.3% due to the additional leap year day.

Table 1: Peak and Energy Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2015	22,888	24,721
Winter 2015-16	22,380	23,172
Summer 2016	22,849	24,706
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 (Forecast)	138.2	-0.5%
2016 Energy (Forecast)	139.7	1.1%

- End of Section

Caution and Disclaimer

The contents of these materials are for discussion and information purposes and are provided "as is" without representation or warranty of any kind, including without limitation, accuracy, completeness or fitness for any particular purpose. The Independent Electricity System Operator (IESO) assumes no responsibility to you or any third party for the consequences of any errors or omissions. The IESO may revise these materials at any time in its sole discretion without notice to you. Although every effort will be made by the IESO to update these materials to incorporate any such revisions it is up to you to ensure you are using the most recent version.

Table of Contents

List of Tables

List of Figures

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 2015 to December 2016. It supersedes the previous forecast released in March 2015 and the previous Ontario Demand Forecast document released in December 2014.

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" (IESO_REP_0266), found on the IESO website at.http://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2015jun.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 February 2014. Data for March and April 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_2015jun.xls) spreadsheet posted alongside the Outlook documents. The spreadsheet's historical tables contain data right back to market opening which would not be practical in a printed document.

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

Electronic copies of the forecast and weather scenarios are available upon request.

- End of Section -

2.0 Demand Forecast

This section presents the demand forecast for the Outlook period. Additional tables are included in the 18-Month Outlook Tables spreadsheet.

Table 2.1 contains the forecast of system weekly peak and energy demand. It also includes 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)
05-Jul-15	22,425	23,892	1,016	2,689	03-Apr-16	18,269	19,024	567	2,576
12-Jul-15	22,888	24,721	814	2,765	10-Apr-16	17,502	18,500	471	2,509
19-Jul-15	22,793	23,893	838	2,668	17-Apr-16	16,845	17,324	496	2,449
26-Jul-15	22,318	24,315	1,035	2,778	24-Apr-16	16,612	16,984	531	2,424
02-Aug-15	22,140	24,319	841	2,767	01-May-16	17,480	19,840	721	2,424
09-Aug-15	21,464	24,489	958	2,725	08-May-16	17,634	20,200	849	2,404
16-Aug-15	21,429	24,016	985	2,711	15-May-16	18,564	21,761	845	2,435
23-Aug-15	21,421	23,682	1,362	2,731	22-May-16	18,898	21,841	1,175	2,443
30-Aug-15	20,263	22,886	1,413	2,608	29-May-16	19,375	21,522	1,330	2,381
06-Sep-15	18,470	21,986	1,370	2,495	05-Jun-16	19,635	23,109	1,292	2,573
13-Sep-15	18,210	20,711	680	2,448	12-Jun-16	20,813	23,529	1,055	2,629
20-Sep-15	17,956	20,079	781	2,471	19-Jun-16	21,568	23,967	835	2,666
27-Sep-15	17,086	18,329	420	2,419	26-Jun-16	22,265	23,929	754	2,738
04-Oct-15	17,201	17,566	554	2,461	03-Jul-16	22,474	24,128	1,016	2,720
11-Oct-15	17,320	17,747	786	2,493	10-Jul-16	22,849	24,706	814	2,767
18-Oct-15	17,822	18,228	507	2,453	17-Jul-16	22,746	23,846	838	2,668
25-Oct-15	17,812	18,350	392	2,536	24-Jul-16	22,293	24,293	1,035	2,781
01-Nov-15	18,288	18,739	318	2,572	31-Jul-16	22,069	24,247	841	2,762
08-Nov-15	19,042	19,437	416	2,650	07-Aug-16	21,394	24,418	958	2,725
15-Nov-15	19,354	20,114	601	2,672	14-Aug-16	21,392	23,979	985	2,715
22-Nov-15	19,833	20,668	342	2,754	21-Aug-16	21,400	23,659	1,362	2,735
29-Nov-15	20,290	21,327	607	2,797	28-Aug-16	20,219	22,855	1,413	2,612
06-Dec-15	20,724	21,848	409	2,856	04-Sep-16	18,732	22,255	1,370	2,508
13-Dec-15	21,009	21,934	555	2,897	11-Sep-16	18,165	20,666	680	2,451
20-Dec-15	20,695	21,787	690	2,882	18-Sep-16	17,927	20,046	781	2,476
27-Dec-15	20,405	22,167	362	2,844	25-Sep-16	17,084	18,327	420	2,427
03-Jan-16	20,690	21,638	528	2,797	02-Oct-16	17,196	17,557	554	2,465
10-Jan-16	22,380	23,172	570	3,024	09-Oct-16	17,322	17,749	786	2,496
17-Jan-16	21,641	22,321	547	2,971	16-Oct-16	17,787	18,195	507	2,456
24-Jan-16	21,801	22,360	483	2,974	23-Oct-16	17,775	18,309	392	2,538
31-Jan-16	21,808	22,371	404	3,010	30-Oct-16	18,247	18,707	318	2,573
07-Feb-16	21,001	21,961	734	2,947	06-Nov-16	18,491	18,886	416	2,636
14-Feb-16	20,395	21,796	635	2,864	13-Nov-16	19,290	20,051	601	2,671
21-Feb-16	20,326	21,723	581	2,825	20-Nov-16	19,762	20,598	342	2,754
28-Feb-16	20,282	21,789	501	2,906	27-Nov-16	20,243	21,276	607	2,798
06-Mar-16	19,872	20,679	531	2,813	04-Dec-16	20,453	21,802	409	2,849
13-Mar-16	19,463	20,462	649	2,748	11-Dec-16	20,963	21,893	555	2,900
20-Mar-16	18,280	19,385	611	2,622	18-Dec-16	20,660	21,756	690	2,888
27-Mar-16	18,367	19,277	569	2,581	25-Dec-16	21,036	22,797	362	2,976

Compared to the previous forecast, the peak and energy demand are higher during the 2015-16 winter but lower throughout the rest of the forecast period.

Figure 2.1: Weekly Energy Demand – History and Forecast

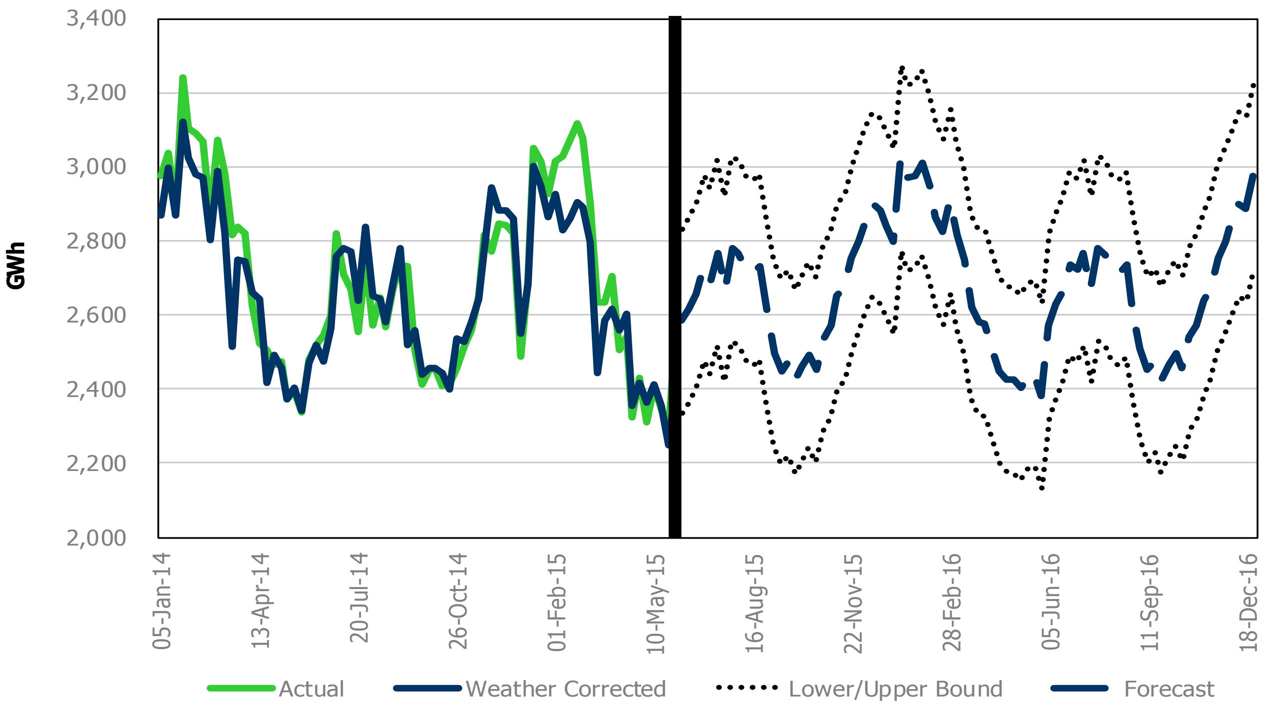
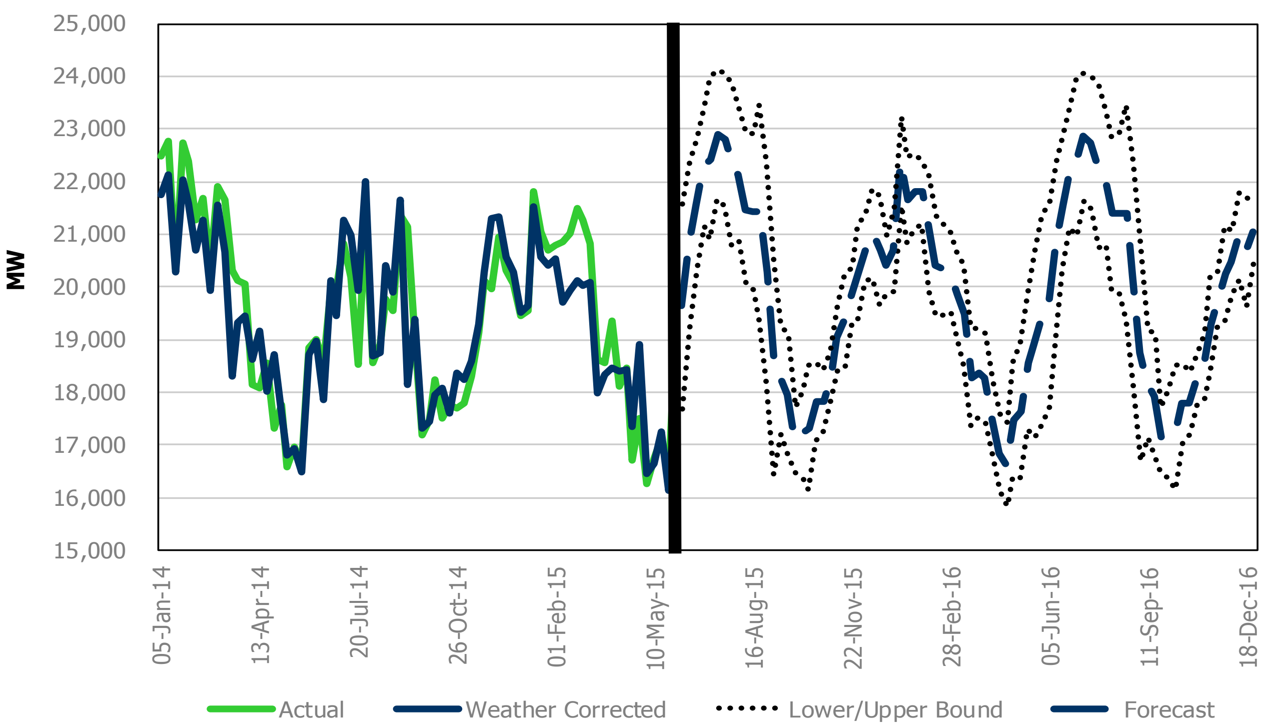


Figure 2.2: Weekly Peak Demand – History and Forecast



- End of Section -

3.0 Historical Review

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

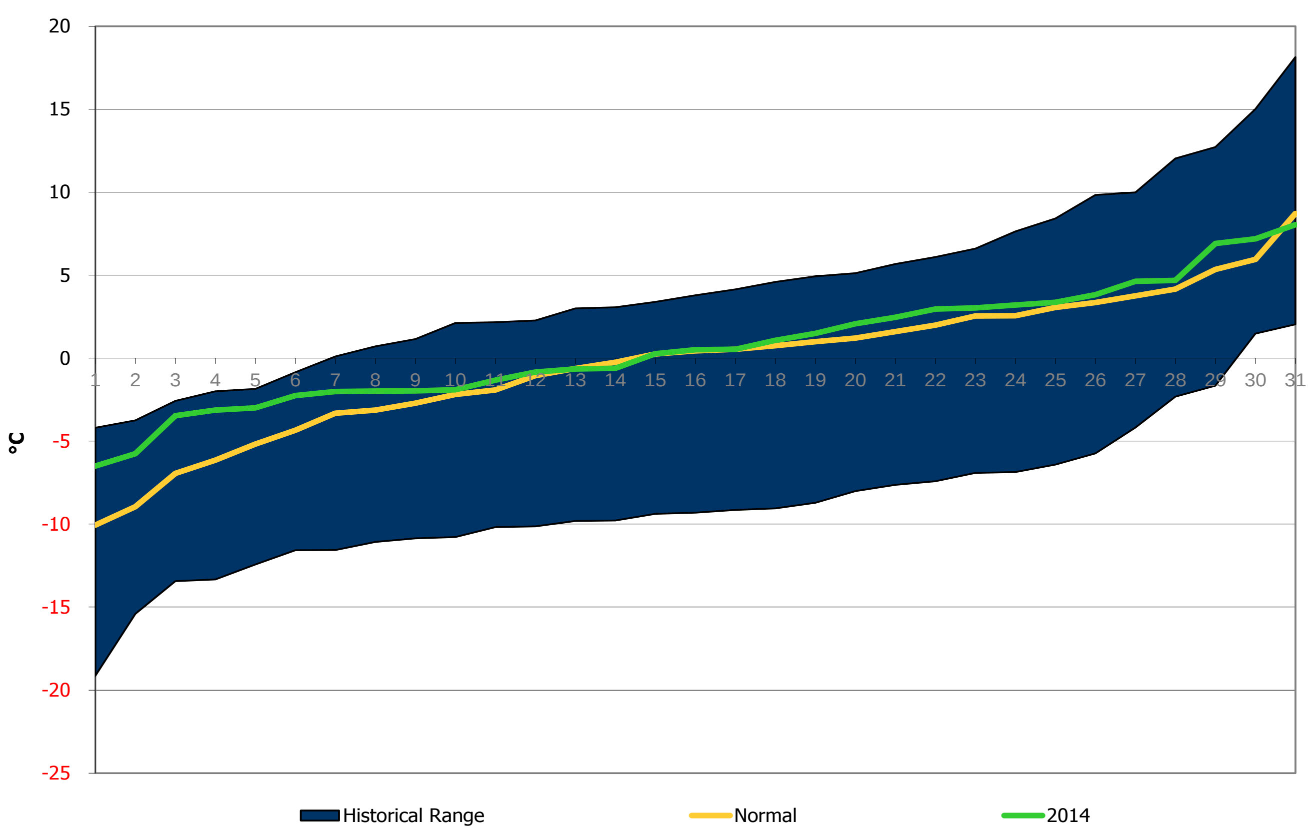
3.1 Six Month Review – December to May

Since the last Ontario Demand document, actuals have been recorded for the period December to May. The winter of 2014-15 was a mixed bag, December was mild, January was fairly typical and February was abnormally cold. The spring was similar to the winter with March being cold, April fairly typical and May warmer than normal. For each month there are notes regarding the weather, actual and weather corrected energy and peak demands as well as wholesale customers' consumption. The information is presented to provide insight into the historical data. At times, the weather and weather corrected values may seem inconsistent. This is due to the fact that weather correction process includes the impact of temperature, humidity, cloud cover and wind speed across six weather stations. As well, when the peak eliciting weather (coldest day) occurs on a weekend or holiday, it can further impact the weather correction process.

<u>December</u>

- December's weather was milder than normal. As it turned out, it was warmer on Christmas Day than it was on Easter. The following figure shows the afternoon high temperature for December ranked from the coldest to warmest day. Therefore, on the left is the coldest day of the month while on the right is the warmest. The band shows the range of temperatures for the past 41 years. The graph shows that the temperature for December 2014 was consistently warmer than normal (the yellow line) and the colder days of the month were significantly warmer.

Figure 3.1: Daily Temperature - December

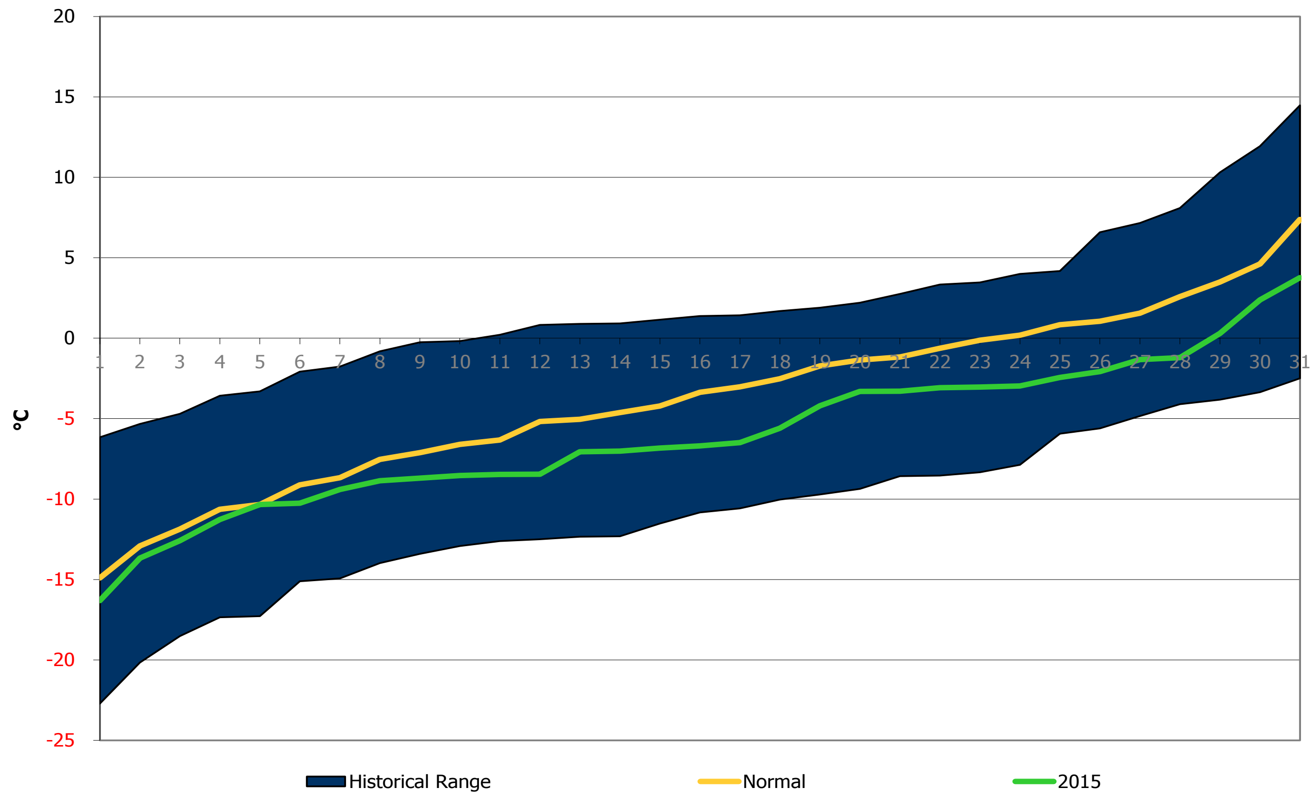


- The peak demand occurred on December 2nd, which was quite early in the month. It was also the third coldest weekday of the month but was preceded by and followed by rather mild days. Therefore, the peak was a rather modest 20,938 MW (21,322 MW weather corrected). This was lower than last December but an increase over 2012. There was a "cold snap" later in the month but it occurred over the holiday period and therefore did not generate high peak demands.
- With the milder weather, monthly energy demand was 12.2 TWh. This was bumped up to 12.4 TWh after correcting for weather, but both values are low by historical standards for December.
- Minimum demand for the month was 11,398 MW which is the lowest December value since market opening and was the result of mild weather over the holidays.
- Wholesale customers' capped off a negative quarter with consumption dropping by 1.4% compared to December 2013.

January

- January was colder than normal. However, the coldest days were not colder than normal. This is best illustrated by the Figure 3.2. The graph shows that the coldest eight days of the month were fairly normal but the remainder of the month was colder than normal.

Figure 3.2: Daily Temperature - January



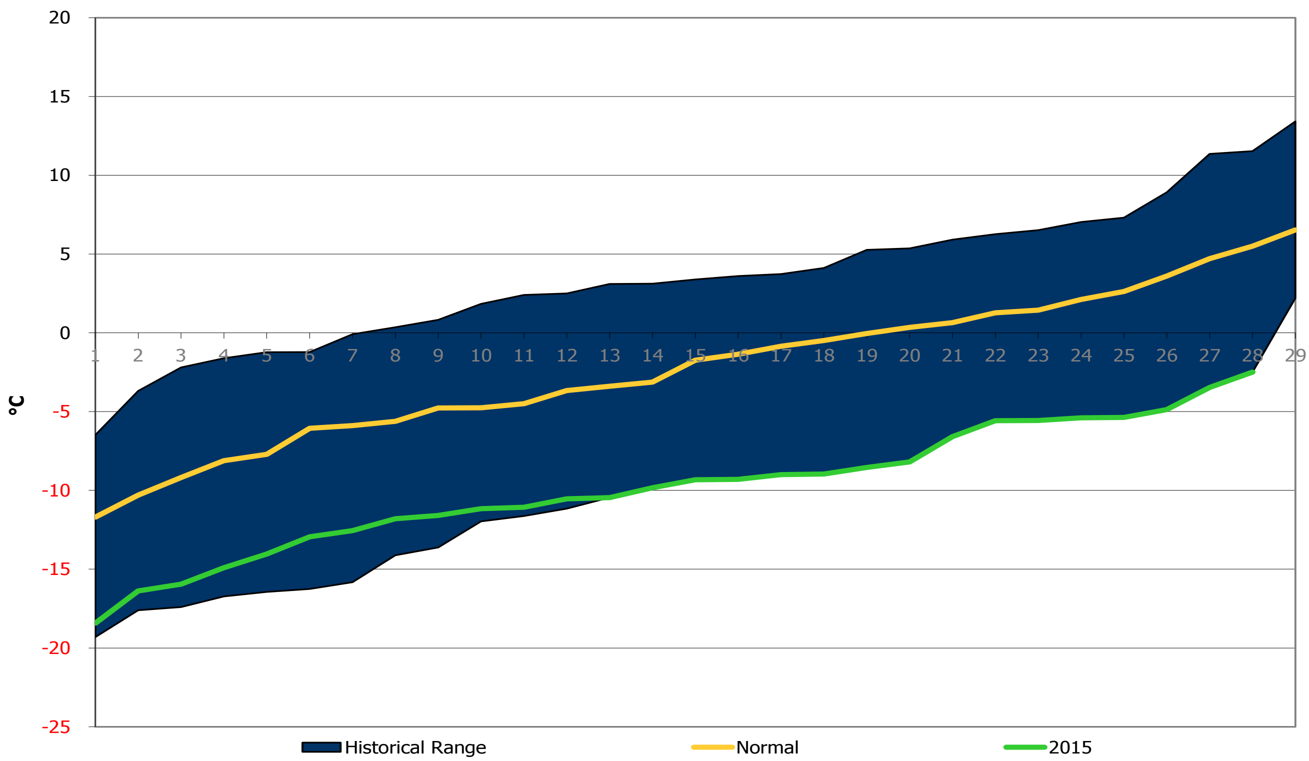
- With the colder weather, the actual demand was higher than the weather corrected value, 13.1 TWh versus 12.8 TWh. Both however were low by historical standards. The actual was the second lowest and the weather corrected the lowest January since market opening.
- Whereas the month was colder than normal, the peak temperature was just slightly colder than normal. The peak demand for the month was on the coldest day and was 21,814 MW (21,531 MW weather corrected). These are quite low by historical standards for January, but this year was different as the ICI significantly reduced the January peak. This was the first time that the ICI was "in play" during the winter.

- Minimum demand for the month was 13,344 MW which was slightly lower than last year's value but higher than recent history. This is a reflection of the weather.
- Wholesale customers' consumption continued the weakness of the last quarter of 2014 into 2015. Year over year consumption fell by 3.2%.

February

- February was very cold. Figure 3.3 definitively describes the weather for the month, as the observed values for 2015 were near the bottom of the range for the 28 days. There were only a handful of days in February's history that were colder.

Figure 3.3: Daily Temperature - February

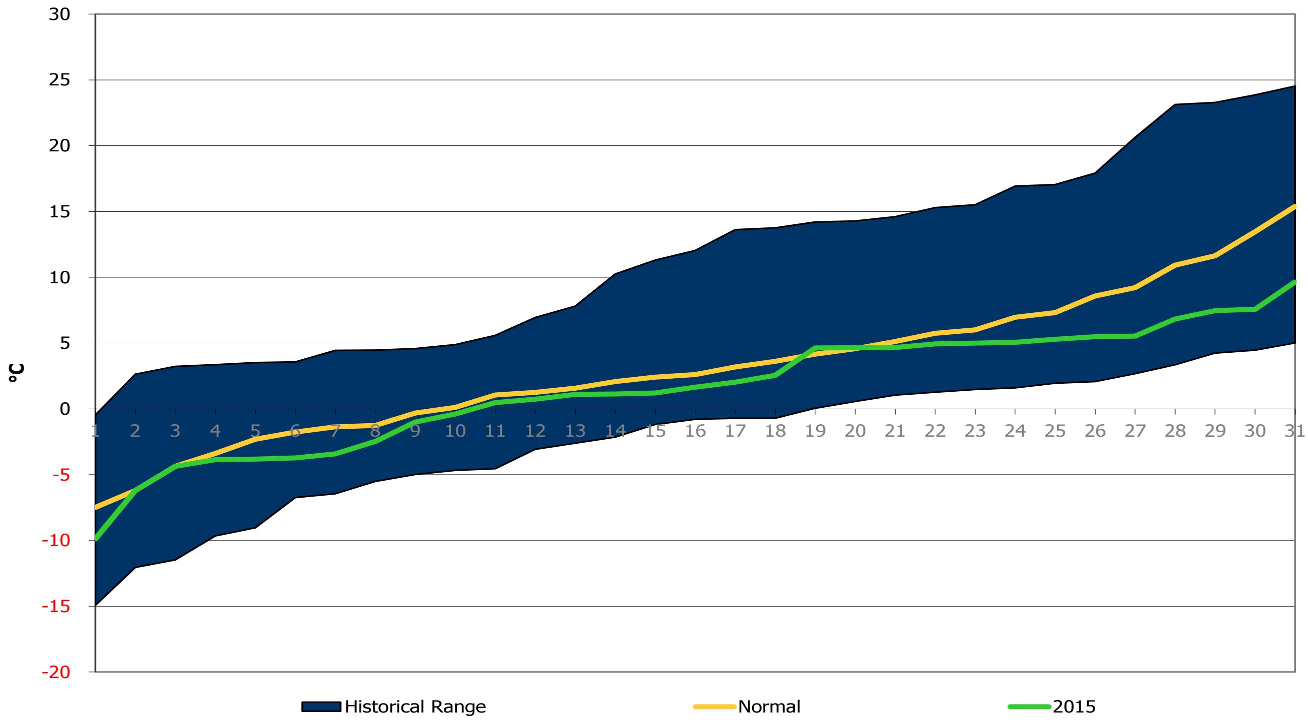


- The February peak was 21,494 MW and occurred on the second coldest day of the month (the coldest weekday). This is not high by historical standards particularly given the weather conditions. However, once again ICI was in play leading to a reduction in demand. The weather corrected value of 20,132 MW was low by historical standards and was due, in part, to the ICI impacts.
- With the colder weather energy demand for the month was the highest for a February since 2008 at 12.3 TWh. However, the weather corrected value was a much more modest 11.5 TWh, which is consistent with the relatively flat levels of demand since the recession.
- The minimum demand was 14,588 MW for the month. Given the cold weather it is not surprising that this is the highest value since February 2007 which was also a cold February.
- Wholesale customers' consumption continued to decline, falling 4.7% compared to the previous February. That marked five consecutive months of contraction.

March

- The weather for March was colder than normal. March can be a transition from colder winter temperatures to warmer spring temperatures. March 2015 was marked by fairly typical colder temperatures but colder than normal weather during the warmer period. Figure 3.4 illustrates this as the line for 2015 deviates from the normal as we go to the right.

Figure 3.4: Daily Temperature - March

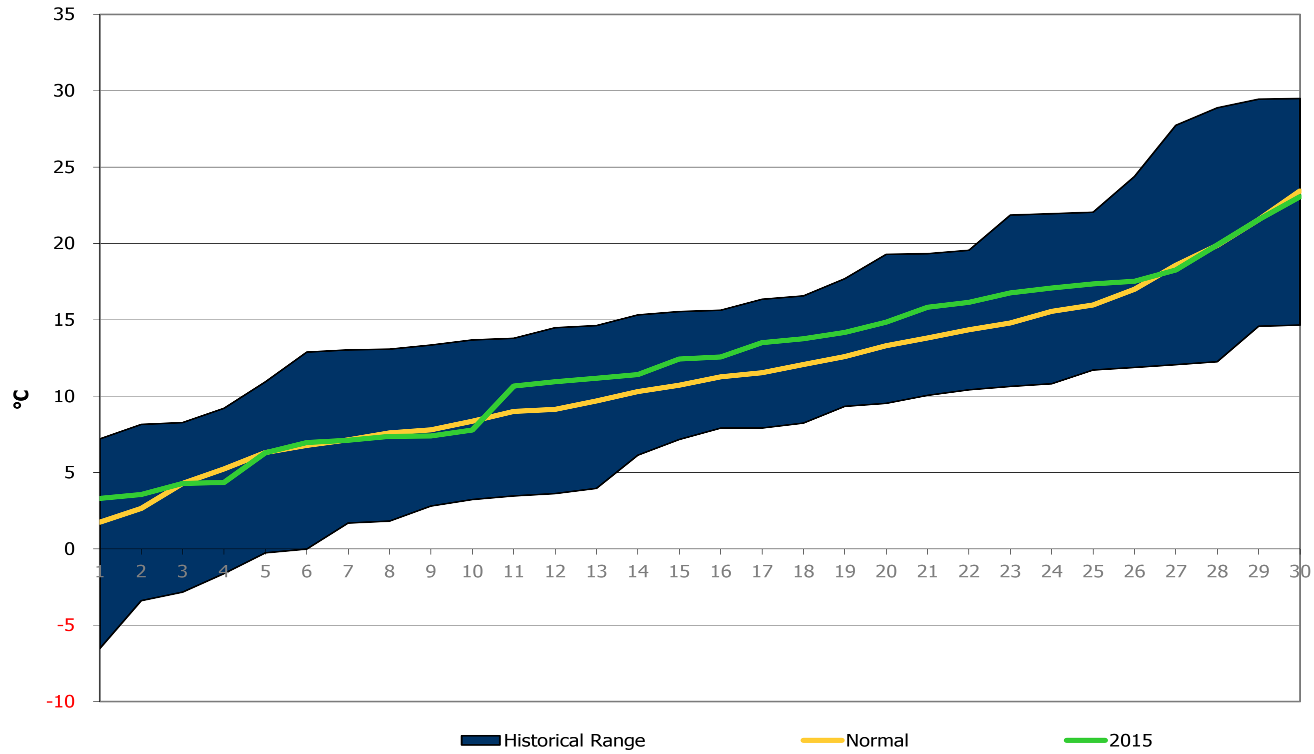


- The actual peak of 20,827 MW occurred on March 5th which was the coldest day of the month. March peaks can be up and down as the weather is in transition but this peak value was a little higher than the average peak since the recession. After adjusting for weather, the peak was 20,070 MW which is on the low side compared to weather corrected March peaks since the recession.
- Energy demand for the month was 12.0 TWh and 11.6 TWh weather corrected. As with the peak values, the actual was in line with recent experience while the weather corrected was low.
- Minimum demand for the month was 12,675 MW which is higher than recent experience. Note that a lower minimum would be driven by warmer temperatures in the month but with March 2015 being colder during the warmer period this led to a higher minimum.
- Wholesale customers' consumption decreased by 6.0% compared to the previous March. This marks six consecutive months of decline and the largest percent decline during that period.

April

- April was pretty much normal with regards to temperature. Since April is a shoulder month weather plays less of a role during this month – much like October. Figure 3.5 shows the temperature for the month.
- The month's peak demand of 18,462 MW and was typical of the month's peaks since the recession. Likewise for the weather corrected peak of 18,900 MW. The peak occurred on April 8th which was the coldest weekday of the month.
- The minimum demand of 10,975 MW is in line with experience since the end of the recession.
- Wholesale customers' consumption continued to slide for the seventh month in a row. This month the decline was 3.7%.

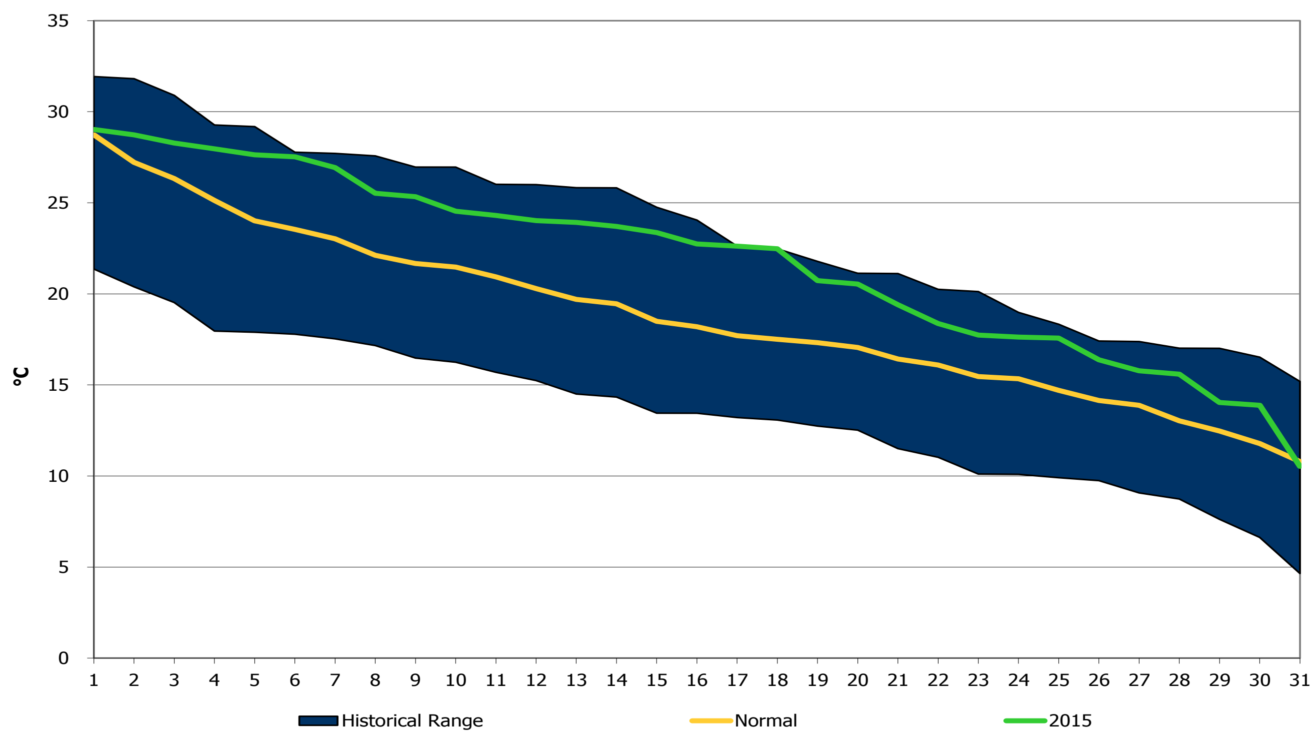
Figure 3.5: Daily Temperature - April



May

- The weather for May was consistently warmer than normal with the exception of the hottest and coldest days which were normal.

Figure 3.6: Daily Temperature - May



- The peaks for May were 19,158 MW actual and 18,033 MW weather corrected which were the lowest since 2009.
- Actual and weather corrected energy demand were both 10.5 and 10.4 TWh respectively. Once again these numbers represent lows for the past five years.
- Minimum demand of 10,869 MW for May 2015 is consistent with the months' observations since the recession. Over that time minimums have fallen in the range of 10,700 to 11,000 MW.
- Despite strong manufacturing job growth in May, the wholesale customers' consumption declined by 2.4% compared to the previous May. This marks eight consecutive months of decline.

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 2014-2015 Weather and Demand Summary

Historical Analysis		December	January	February	March	April	May
Actual Weather	Average Temperature (°C)	1.8	-4.7	-9.3	2.0	12.4	21.6
	Minimum Temperature (°C)	-6.9	-15.7	-19.3	-9.6	1.8	8.7
	Maximum Temperature (°C)	10.1	4.1	-1.6	11.5	23.4	28.8
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)	20,938	21,814	21,494	20,827	18,462	19,158
	Average Hour (MW)	16,348	17,634	18,307	16,189	14,451	14,176
	Minimum Hour (MW)	11,398	13,344	14,588	12,675	10,975	10,657
	90th Percentile (MW)	19,037	20,100	20,279	18,117	16,390	16,588
	Percent above 20,000 (MW)	2.3%	11.3%	15.3%	0.7%	0.0%	0.0%
	# of Hours Above 20,000 (MW)	17	84	103	5	0	0
	Energy Demand (GWh)	12,163	13,120	12,302	12,045	10,405	10,547
Weather Corrected Demand	Peak Demand (MW)	21,322	21,531	20,132	20,070	18,900	18,033
	Energy Demand (GWh)	12,363	12,843	11,468	11,570	10,547	10,401
Forecast Demand	Peak Demand (MW)	21,238	22,294	21,017	19,841	18,121	19,370
	Energy Demand (GWh)	12,769	13,069	11,529	11,857	10,542	10,636

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

Demand for the six-month period of December 2014 to May 2015 was down 2.8% over the same period a year earlier. The previous winter had an extremely cold March while this past winter had an extremely cold February. Weather would not be a big factor in the year over year decline. Not surprisingly, the weather corrected demand had a very similar 2.7% reduction.

The past six months have seen a change in the underlying load at the consumer level. Previously, distributors' loads have declined while wholesale customers have been showing year over year increases. However, since the last quarter of 2014, wholesale loads have also been declining. For the past six months, distributor loads have dropped by 1.9% compared to the same months a year earlier. Wholesale loads have dropped by 3.6% over the same periods.

Figure 3.7 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 8 months.

Figure 3.7: Wholesale Customers' Year-over-Year Change in Consumption

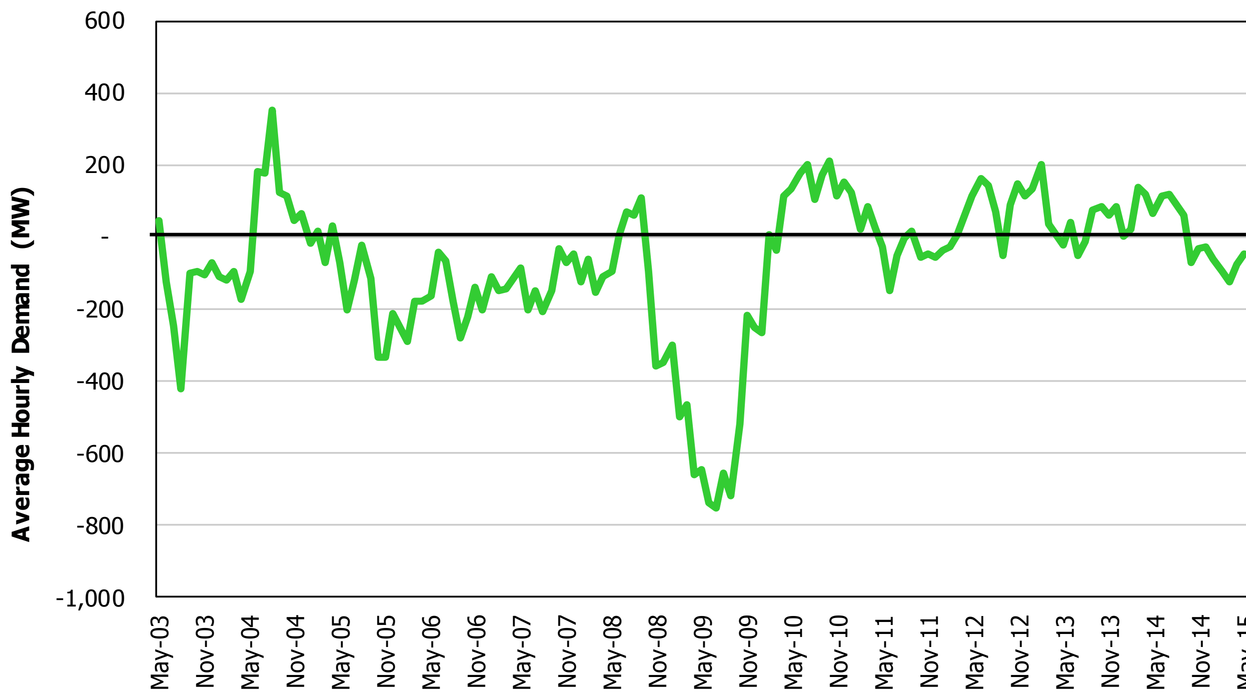


Figure 3.8: Wholesale Customers' Average Hourly Consumption by Industry Segment

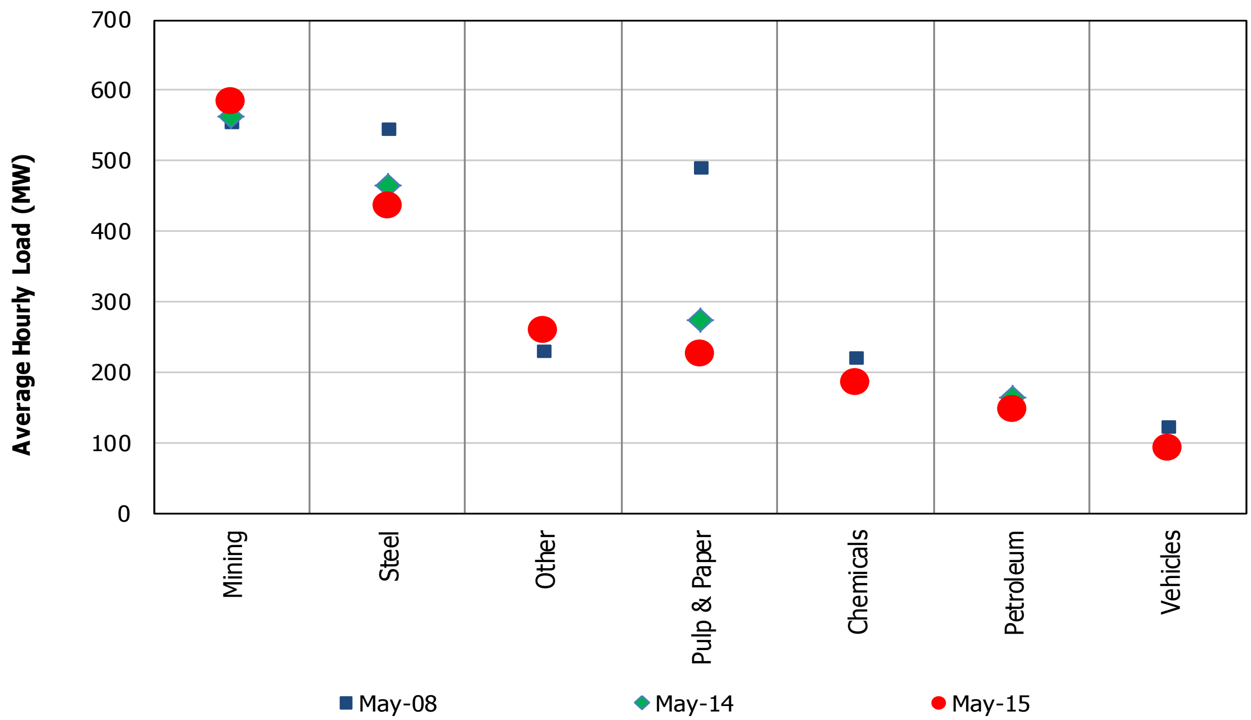


Figure 3.8 shows the wholesale customers' average hourly load by industry segment for the past six months (December to May) compared to the same six months prior to the recession (December 2007 to May 2008) and a year ago. Only the Mining and Other sector have shown an increase compared to both the pre-recessionary levels and last year.

The Pulp & Paper sector was the industrial segment with the largest electricity consumption when the market opened in 2002. In 2003, the segment consumed 6.5 TWh of electricity. With more recycled content and the dramatic drop in demand for newsprint, consumption had dropped to 4.3 TWh in 2008 and 2.3 TWh in 2014. The sector is not expected to rebound. Mining is now the largest electricity consuming segment. Based on investment intentions, it will likely remain the highest consuming segment. The remaining sectors have stabilized at a slightly lower level than their pre-recessionary loads.

Overall energy demand has remained fairly flat following the recession. Although economic expansion and population growth should lead to higher electricity consumption, two main factors are working to offset that growth. Conservation helps offset demand growth by effectively reducing the need for electricity. Embedded generation doesn't reduce the need for electricity but does offset electricity that would have been provided from the grid. Combined, both have acted to offset any increased need for grid supplied electricity.

Figure 3.9 shows monthly energy demand and embedded generation output. Though embedded generation shows seasonal volatility, the underlying upward trend is quite evident in the graph. Annual embedded generation topped 5.2 TWh in 2014, 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.

Figure 3.9: Monthly Energy Demand and Embedded Generation

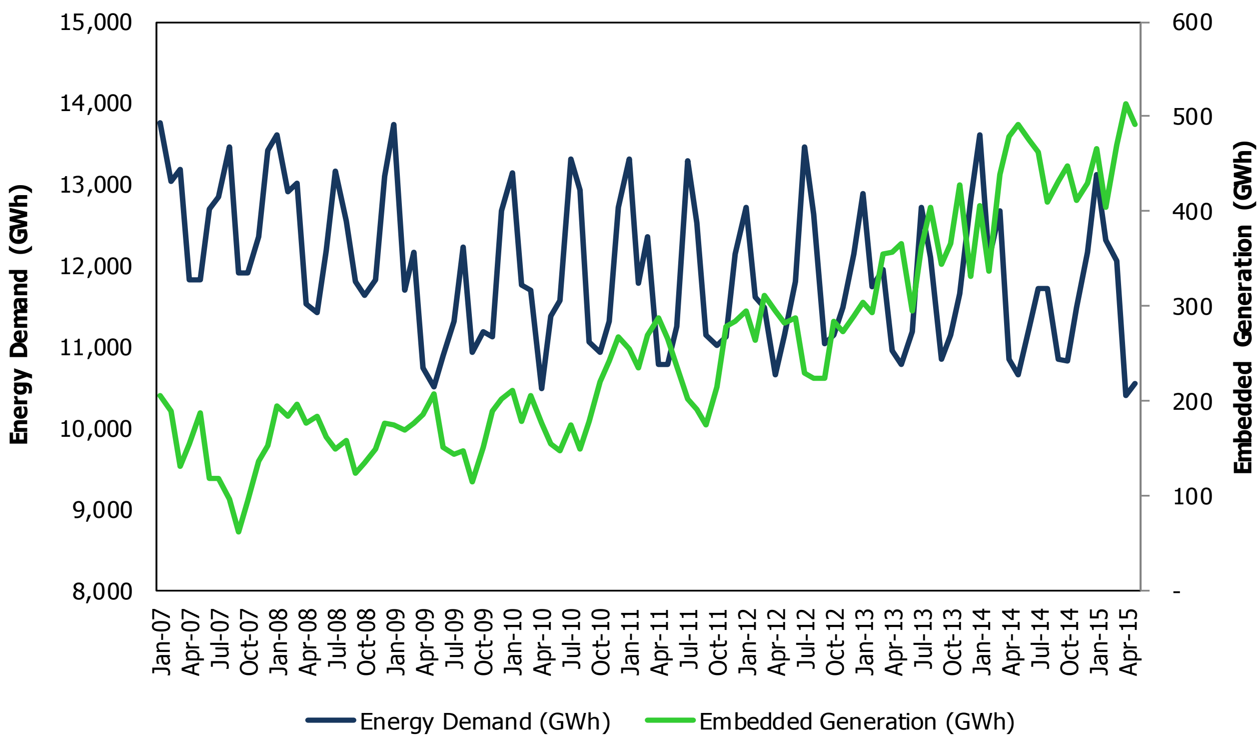


Table 3.2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week, and notes any item of significance for the week. If the weather-corrected demand is greater than the actual demand, it means that the actual weather was milder than normal. Additional history is available in the 18-Month Outlook Tables spreadsheet in Table 3.3.1.

Table 3.2: Historical Weekly Energy Demand

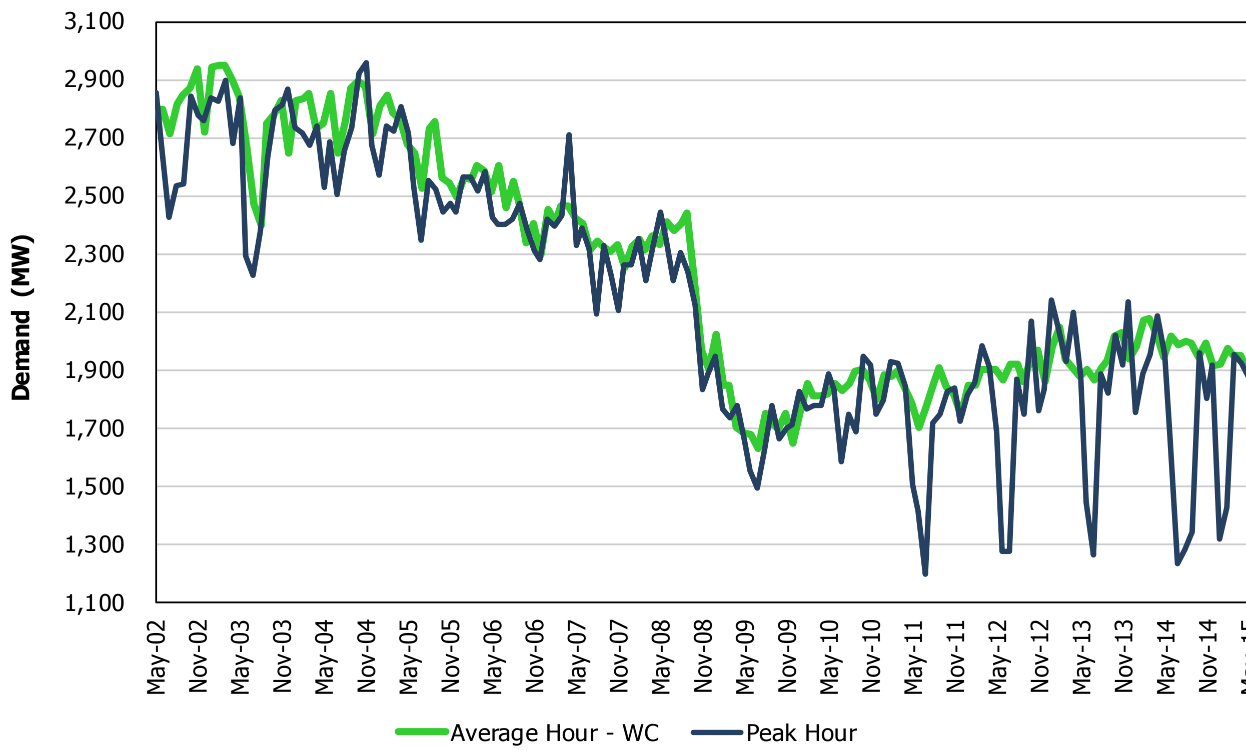
Week Number	Week Ending	Peak Day	Actual Energy (GWh)	Corrected Energy (GWh)	Notes
49	07-Dec-14	02-Dec-14	2,847	2,881	
50	14-Dec-14	08-Dec-14	2,844	2,882	
51	21-Dec-14	18-Dec-14	2,818	2,859	
52	28-Dec-14	22-Dec-14	2,487	2,548	Christmas Day
1	04-Jan-15	03-Jan-15	2,695	2,684	New Year's Day
2	11-Jan-15	07-Jan-15	3,051	3,000	
3	18-Jan-15	13-Jan-15	3,016	2,946	
4	25-Jan-15	21-Jan-15	2,927	2,864	
5	01-Feb-15	27-Jan-15	3,014	2,925	
6	08-Feb-15	02-Feb-15	3,029	2,828	
7	15-Feb-15	12-Feb-15	3,071	2,858	
8	22-Feb-15	19-Feb-15	3,118	2,903	Family Day
9	01-Mar-15	23-Feb-15	3,075	2,892	
10	08-Mar-15	05-Mar-15	2,904	2,797	
11	15-Mar-15	09-Mar-15	2,634	2,444	
12	22-Mar-15	18-Mar-15	2,635	2,585	
13	29-Mar-15	23-Mar-15	2,705	2,616	
14	05-Apr-15	30-Mar-15	2,504	2,559	Good Friday
15	12-Apr-15	08-Apr-15	2,542	2,601	Easter Monday
16	19-Apr-15	16-Apr-15	2,325	2,353	
17	26-Apr-15	23-Apr-15	2,430	2,415	
18	03-May-15	27-Apr-15	2,309	2,362	
19	10-May-15	08-May-15	2,407	2,412	
20	17-May-15	11-May-15	2,345	2,354	
21	24-May-15	18-May-15	2,295	2,247	Victoria Day
22	31-May-15	26-May-15	2,558	2,414	

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 21,814 MW, which was lower than last winter's peak (22,774 MW). However, at the time of this winter's peak, there was significant ICI activity with savings estimated at over 1,000 MW of demand response. Last winter's peak had no such ICI activity. As well, there was an additional 55 MW of demand response through other programs. This is unusual as it represented the first time that ICI activity had occurred in the winter. As the ICI program runs from May to April, the mild summer of 2014 combined with a colder January and February meant that many of the ICI peak days occurred in the winter. 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 late afternoon as air conditioners worked to dispel the accumulated heat. Now, the embedded solar "carving out" demand in the middle of the day is having the effect of pushing the peak later in the day where solar output is declining more rapidly than demand. Figure 3.11 shows how embedded solar is impacted demand on a summers' day. For August 4^{th}, 2014 the peak occurred in hour ending 17. However, by adding back the estimated output of embedded solar, the result is that the actual demand at the consumer would have peaked in hour ending 14. This is a dramatic shift (and was purposely picked to illustrate the point); most times the shift is simply by one hour. The important point is that the shift of the peak hour is happening frequently, and for the summer of 2014 weekday peaks were pushed later in the day over 38% of the time.

Figure 3.11: Embedded Solar Impacts Timing of Peaks

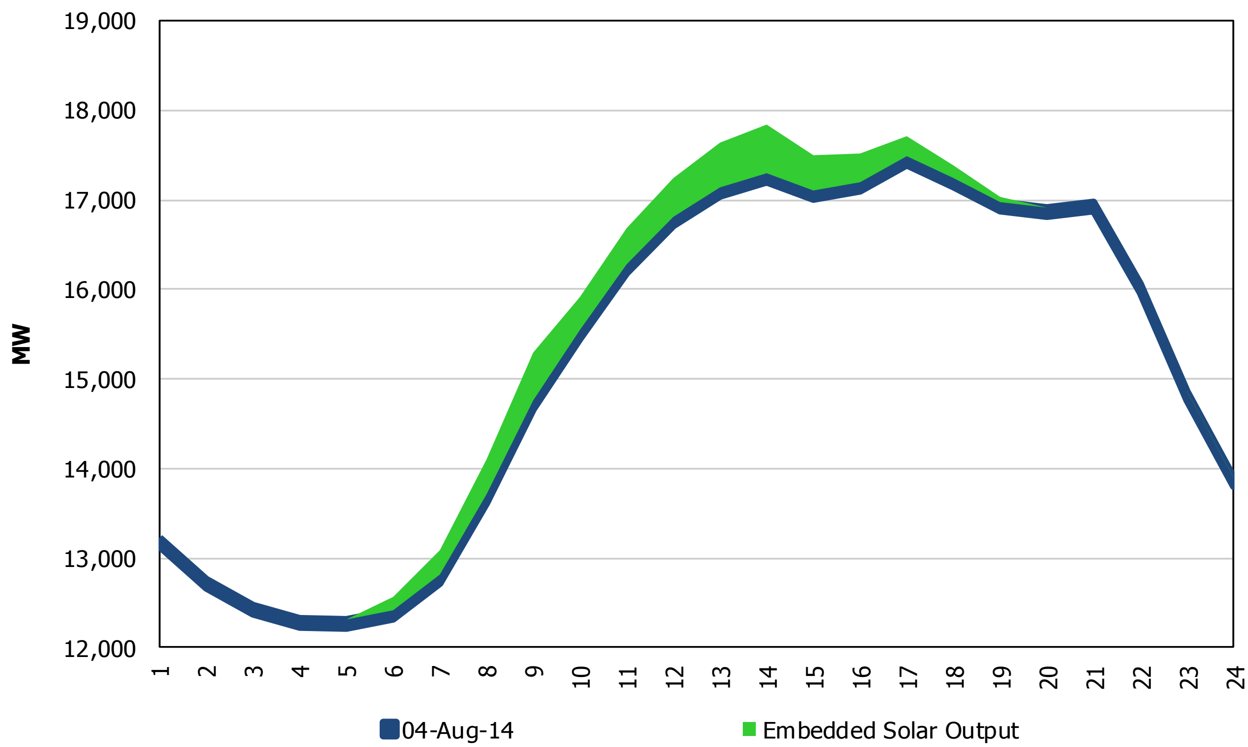
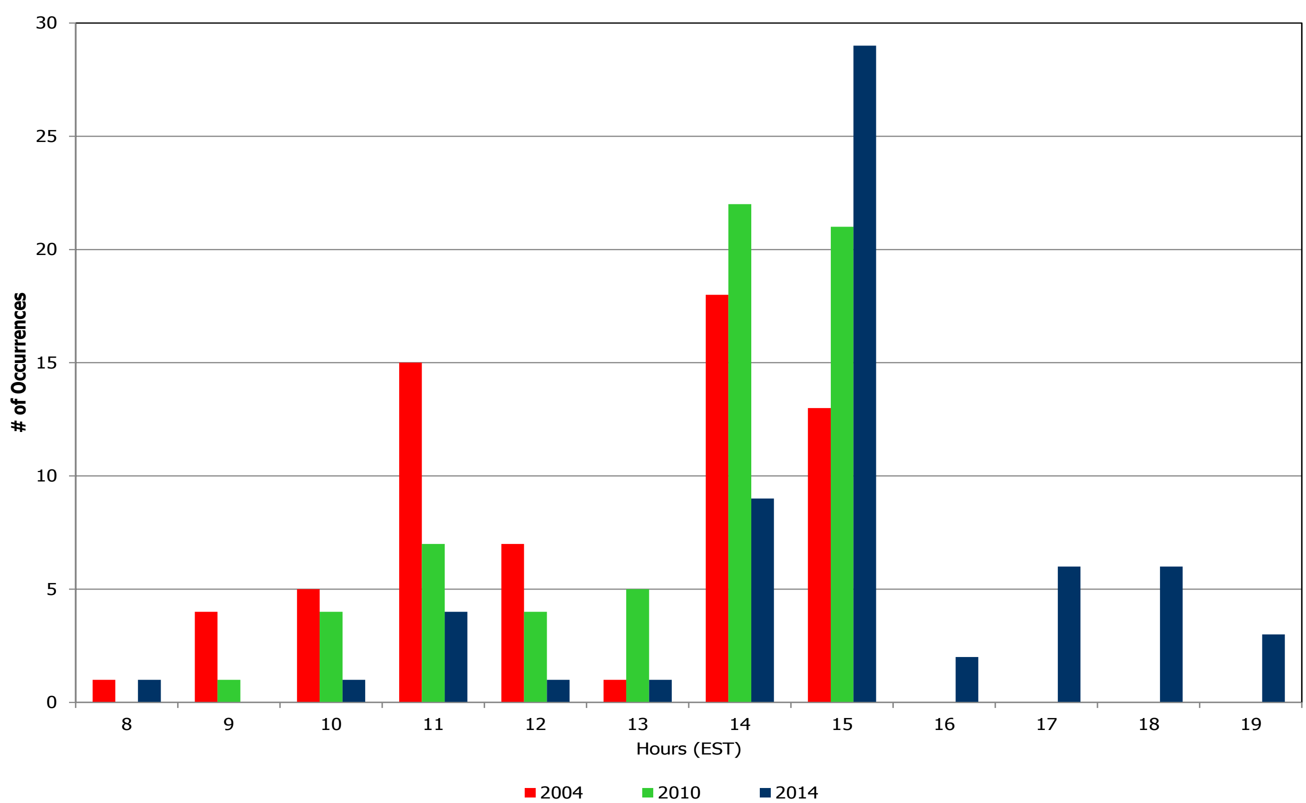


Figure 3.12 shows that summer weekday peaks are moving to later in the day. Although most peaks still occur during hours 14 and 15, the number of peaks occurring later in the day has increased.

Figure 3.12: Summer Weekday Peak Hour Distribution



The interesting aspect of the seasonal peaks is that the winter peak has less underlying growth, but fewer factors 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 winter 2014-15 peak demand which occurred on January 7th during hour 19 EST. The actual recorded peak demand was 21,595 MW. However, as the chart illustrates, demand would have been higher if not for a number of mitigating factors. The peak demand was reduced by demand measures (55 MW), embedded generation (492 MW) and estimated ICI impacts (1,184 MW). This analysis does not show the impact of conservation, which also would have contributed to a higher reconstituted demand number.

Figure 3.13: Anatomy of a Winter Peak

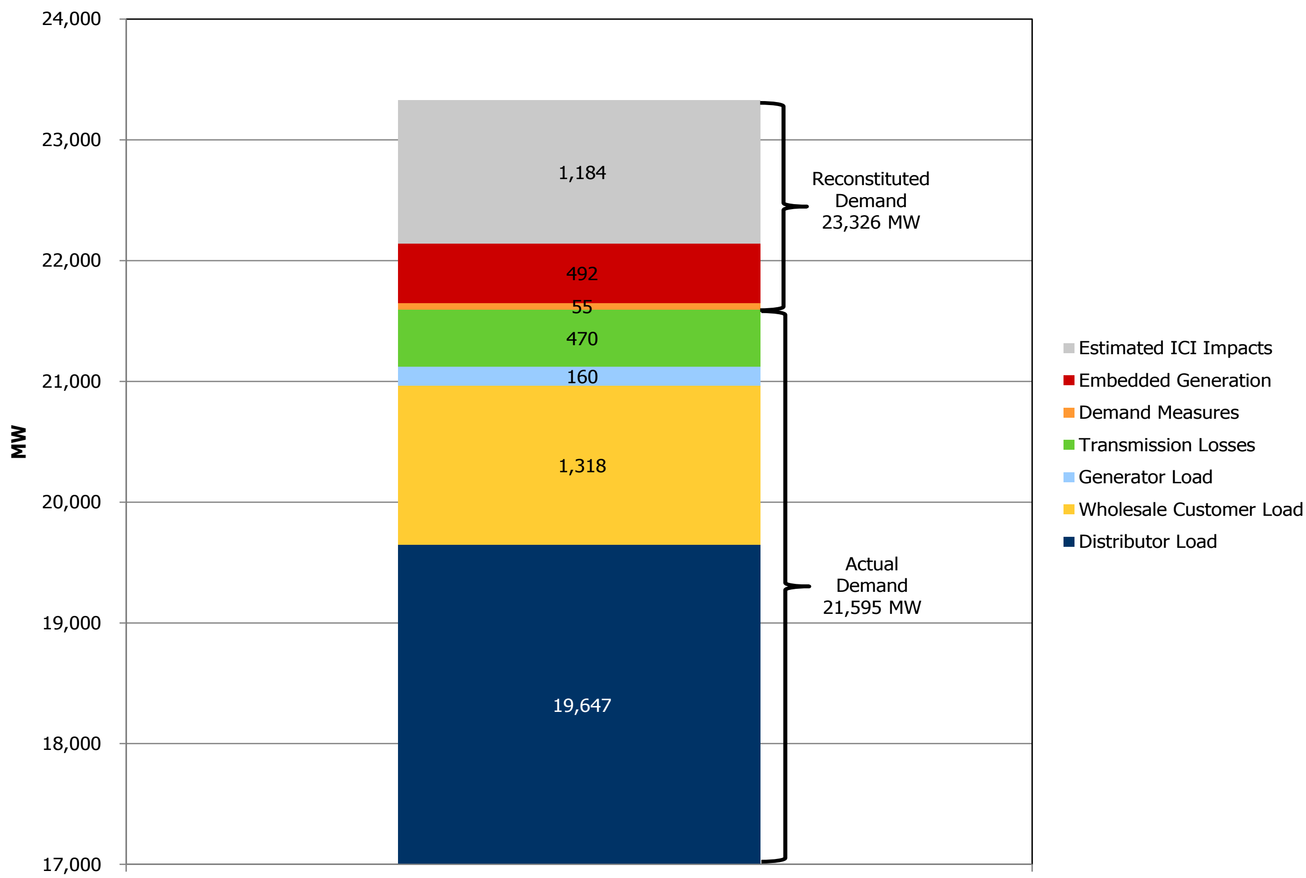


Table 3.3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3.3: Historic Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
49	07-Dec-14	02-Dec-14	20,938	21,322	1.3
50	14-Dec-14	08-Dec-14	20,319	20,548	-1.2
51	21-Dec-14	18-Dec-14	20,063	20,275	2.3
52	28-Dec-14	22-Dec-14	19,439	19,510	-0.7
1	04-Jan-15	03-Jan-15	19,538	19,644	1.6
2	11-Jan-15	07-Jan-15	21,814	21,531	0.1
3	18-Jan-15	13-Jan-15	21,028	20,570	-15.7
4	25-Jan-15	21-Jan-15	20,697	20,396	-11.6
5	01-Feb-15	27-Jan-15	20,803	20,525	-3.0
6	08-Feb-15	02-Feb-15	20,857	19,686	-6.8
7	15-Feb-15	12-Feb-15	21,018	19,926	-11.3
8	22-Feb-15	19-Feb-15	21,494	20,132	-14.5
9	01-Mar-15	23-Feb-15	21,272	20,010	-15.8
10	08-Mar-15	05-Mar-15	20,827	20,070	-15.5
11	15-Mar-15	09-Mar-15	18,627	17,984	-9.6
12	22-Mar-15	18-Mar-15	18,557	18,314	5.4
13	29-Mar-15	23-Mar-15	19,345	18,464	2.0
14	05-Apr-15	30-Mar-15	18,102	18,409	-2.9
15	12-Apr-15	08-Apr-15	18,462	18,422	6.9
16	19-Apr-15	16-Apr-15	16,688	17,346	2.4
17	26-Apr-15	23-Apr-15	17,495	18,900	14.9
18	03-May-15	27-Apr-15	16,269	16,444	2.8
19	10-May-15	08-May-15	16,726	16,627	12.1
20	17-May-15	11-May-15	17,107	17,238	24.1
21	24-May-15	18-May-15	16,428	16,127	19.2
22	31-May-15	26-May-15	19,158	18,033	28.2

3.4 Load Duration Curves

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

The figures are not weather-corrected so the weather will influence the shape of each of the graphs. The spring and fall load duration curves are more heavily influenced by the level of economic activity than by the weather. Those load duration curves show that demand remains low by historical standards. The winter curve illustrates the cold winters the past two years and the summer curve shows how mild the summer of 2014 was.

Figure 3.14: Spring Load Duration Curve

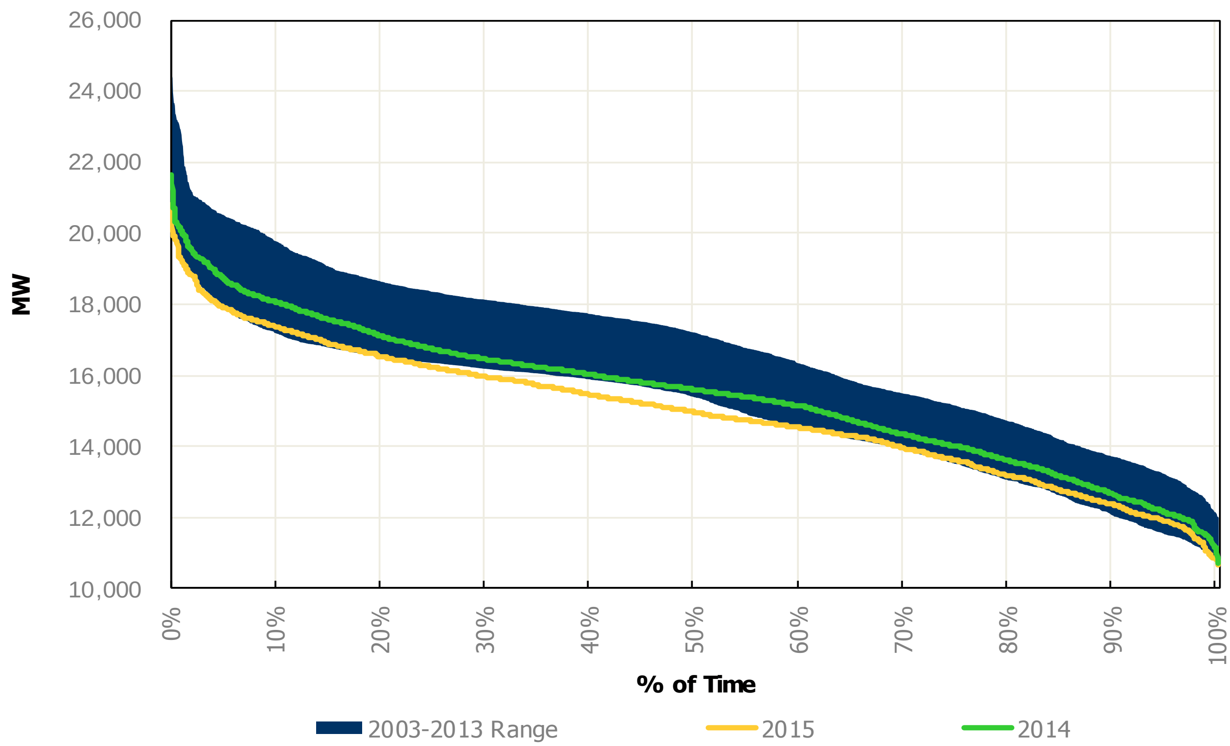


Figure 3.15: Winter Load Duration Curve

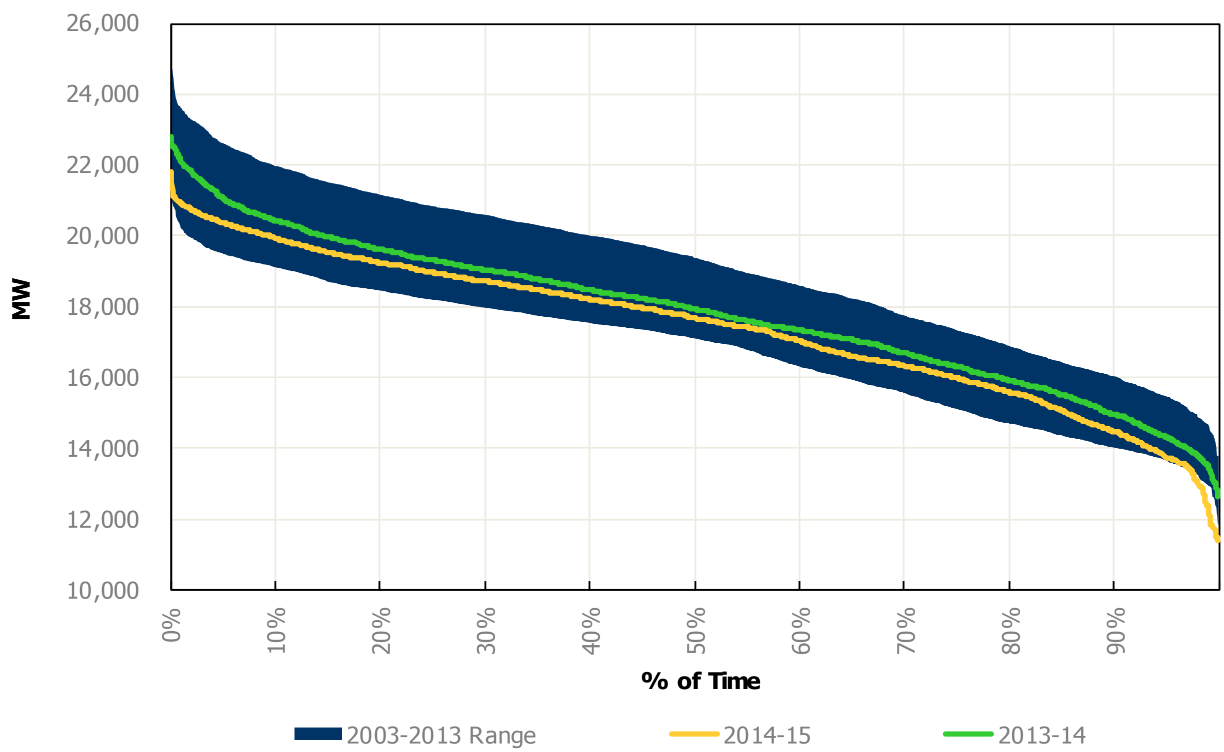


Figure 3.16: Fall Load Duration Curve

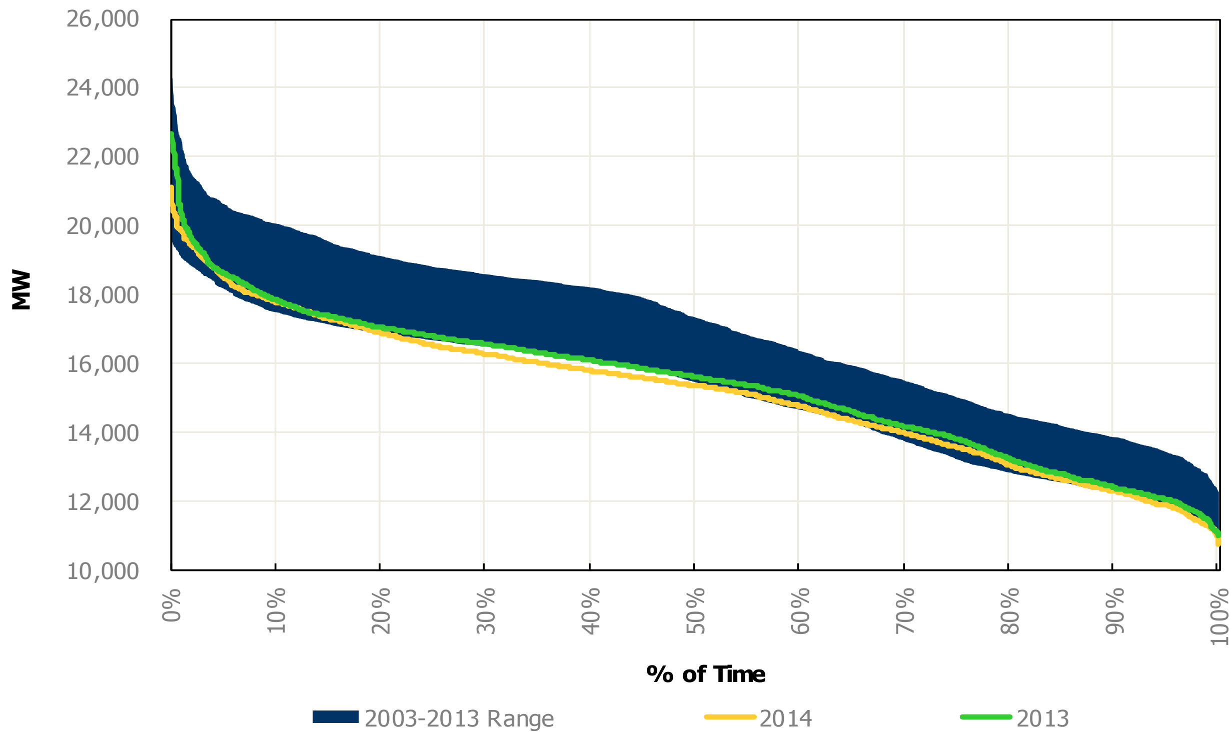
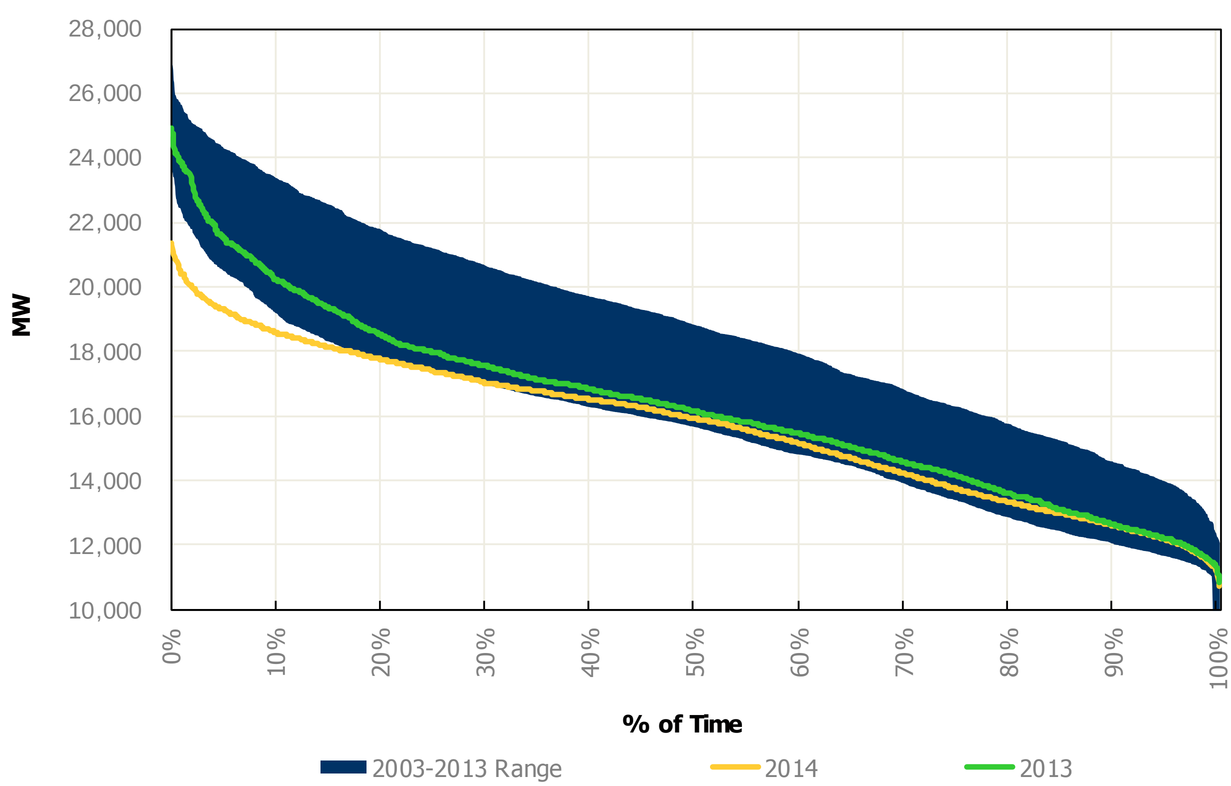


Figure 3.17: Summer Load Duration Curve



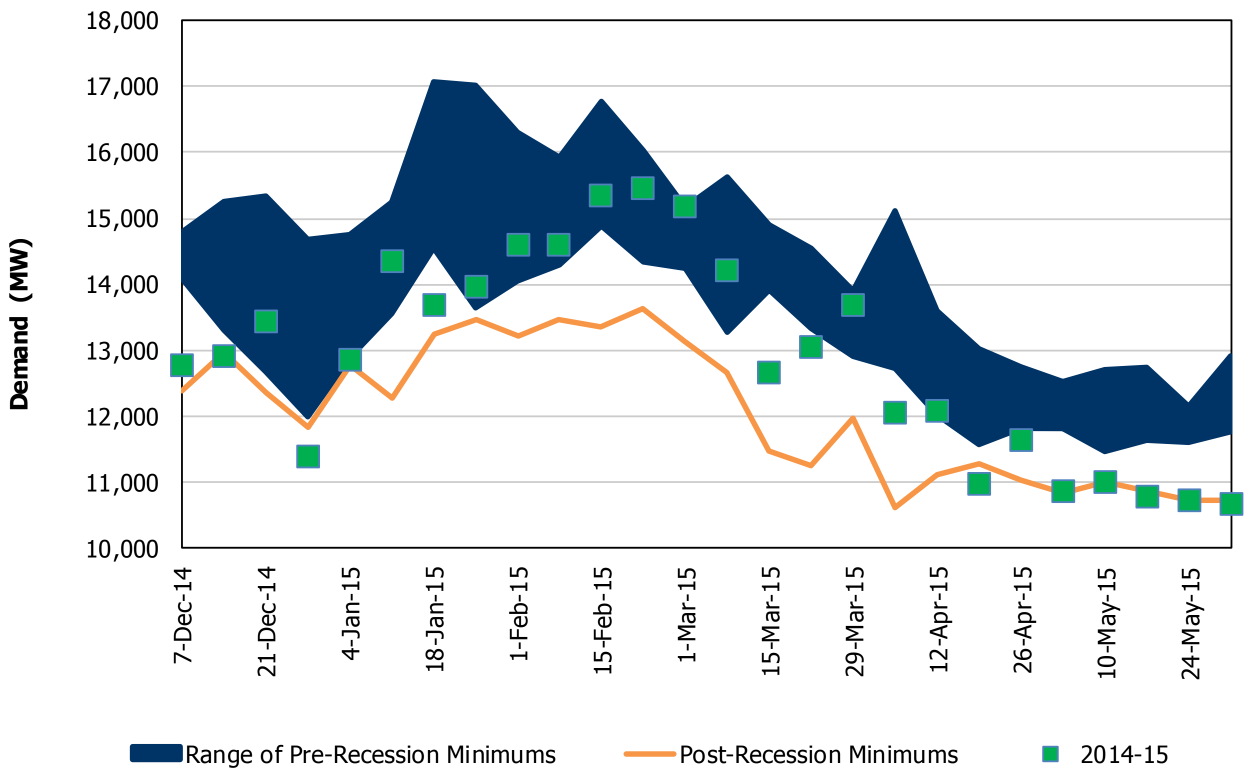
3.5 Historical Minimum Demand

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. With the colder weather over the course of the last six months, minimums have been driven by the weather more than the level of economic activity. Most of the weekly minimums come on the weekend or holidays when the level of economic activity is lower.

During the recession, load was not affected proportionally. Overnight loads bore a higher proportion of load loss as industries cut overnight and weekend shifts first. As well, overnight loads are the least weather sensitive, so that the economic reductions would have a more profound impact on minimums than on overall energy demand.

Figure 3.18 shows the minimum weekly demands for the period December 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 mild weather over Christmas led to the low value on the left hand side. Colder weather through January and February led to higher minimums. However, the spring minimums have been following along the post-recessionary lows, reflecting the recent weakness in the industrial sectors.

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" (IESO_REP_0266) (found on the IESO web site at hhttp://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2015jun.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. 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.

Despite being five years removed from the recession, the economy still seems to be unable to gain any significant traction that would lead to stronger sustained growth. Whether it was due to lingering debt concerns or low consumer confidence, the economy has remained in a period of low growth.

During this period Canada always had the enviable position of low interest rates, relatively lower levels of indebtedness, bountiful natural resources and a highly skilled and productive workforce. However, those factors were not sufficient to spur higher growth as Canada has always been a trading nation and we were therefore not immune to the effects of the global situation.

Three recent developments bode well for Ontario's economy – the depreciation of the Canadian dollar, the strength of the U.S. economy and the drop in energy prices. Ontario's manufacturing sector is export oriented and the lower dollar and U.S. growth means that demand for goods is up and the province's suppliers are more competitively priced. At the same time, lower energy prices also reduce input costs for business thereby helping the bottom line.

While these factors are beneficial, it will take time for these developments to translate into more manufacturing jobs, higher GDP and an increased demand for electricity. Sustained growth requires energy prices, the dollar and U.S. growth to stabilize at these levels – if they continue to fluctuate and bounce around, economic growth will not gain the necessary traction.

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 (%)
2000	5,801	3.2	67.4	7.1	1.128	2.39
2001	5,924	2.1	70.3	4.2	1.150	1.88
2002	6,014	1.5	79.6	13.3	1.169	1.65
2003	6,203	3.1	80.9	1.7	1.198	2.49
2004	6,310	1.7	79.9	-1.3	1.219	1.78
2005	6,390	1.3	73.2	-8.4	1.237	1.49
2006	6,485	1.5	67.8	-7.4	1.256	1.53
2007	6,585	1.6	62.8	-7.4	1.275	1.47
2008	6,664	1.5	71.9	14.6	1.294	1.50
2009	6,511	-2.3	47.9	-33.3	1.283	-0.82
2010	6,599	1.4	57.1	19.1	1.300	1.28
2011	6,724	1.9	65.2	14.3	1.321	1.62
2012	6,776	0.8	74.4	14.1	1.336	1.14
2013	6,876	1.5	58.6	-21.2	1.354	1.33
2014	6,927	0.7	56.2	-4.2	1.366	0.93
2015 (f)	6,997	1.0	54.2	-3.4	1.380	1.03
2016 (f)	7,077	1.2	56.0	3.2	1.396	1.12

In the previous reports, we highlighted the shifting patterns in Ontario's employment as a measuring stick for sustained growth. Since the recession, it had been the case that growth was sector or region specific and not broad based. To generalize, much of the growth was centered in the service sector and into the GTA.

Figure 4.1 shows the year over year change in employment for Ontario, the Toronto zone and all other zones combined. Since the start of 2014, employment growth has been fairly robust outside the GTA. However, the GTA has shed jobs throughout the last half of 2014 and into the start of 2015. Broad based growth would see growth across the province and not this cycle of back and forth. Although just one month's data May showed growth across the province.

Figure 4.2 shows the year over year changes in employment broken down into services, manufacturing and other goods (mining, construction, agriculture, forestry etc.). Though most jobs continue to be within the service sector, the "other goods" sector did show renewed strength. May 2015 had an increase in manufacturing employment, which was the first year over year increase in over two years. Whether that data is just a random blip or the start of a trend will be born out over the course of the year. However given the lower dollar and U.S. economic growth, the opportunity is there for a resurgent manufacturing sector.

Figure 4.1: Zonal Employment Growth

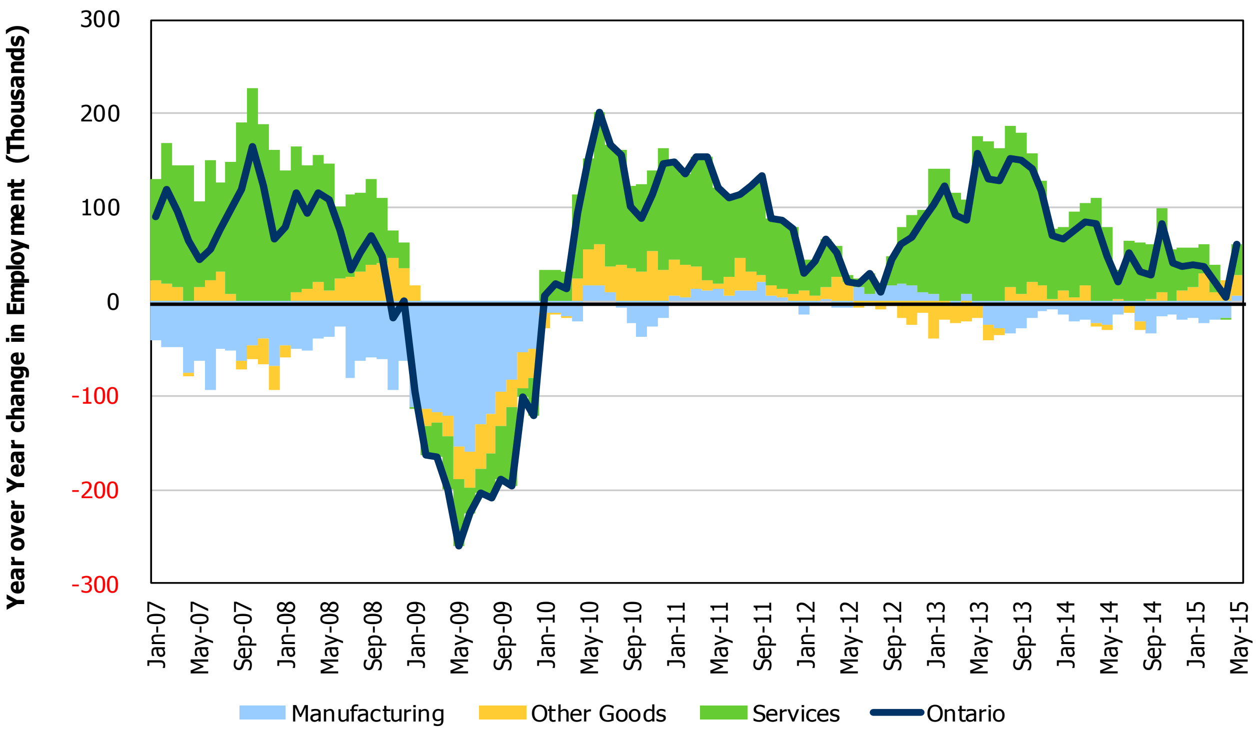
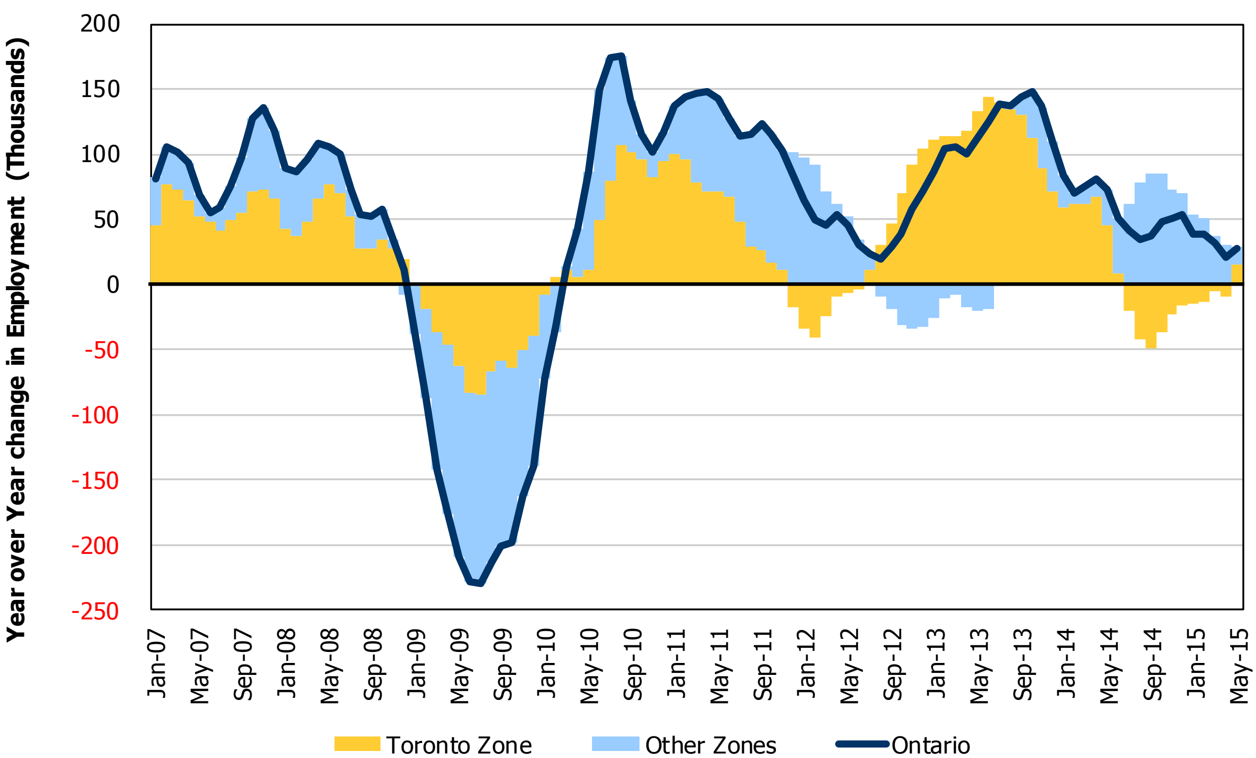


Figure 4.2: Composition of Ontario's Employment Growth



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 we use the maximum, rather than the median value from the sorted 31-year history.

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. Originally, the program was limited to those who have a peak of 5 MW or higher. This expansion should lead to a greater reduction in demand during the five peak days and the initial analysis bears that out. Estimated peak reductions averaged 850 MW for the five days in 2013, and preliminary estimates put the average reductions for the five days at just over 1,000 MW for this past ICI period. Prior to this past ICI period (May 2014 to April 2015), 17 of the 20 peak days had occurred in July, 1 in June, 1 in August and 1 in September. With the mild summer of 2014, the five peak days of the past ICI period occurred in January, February (2), August and September. The impact of the ICI stretches beyond the five peak days as Class A customers will be “guessing” which days fall within those five days.

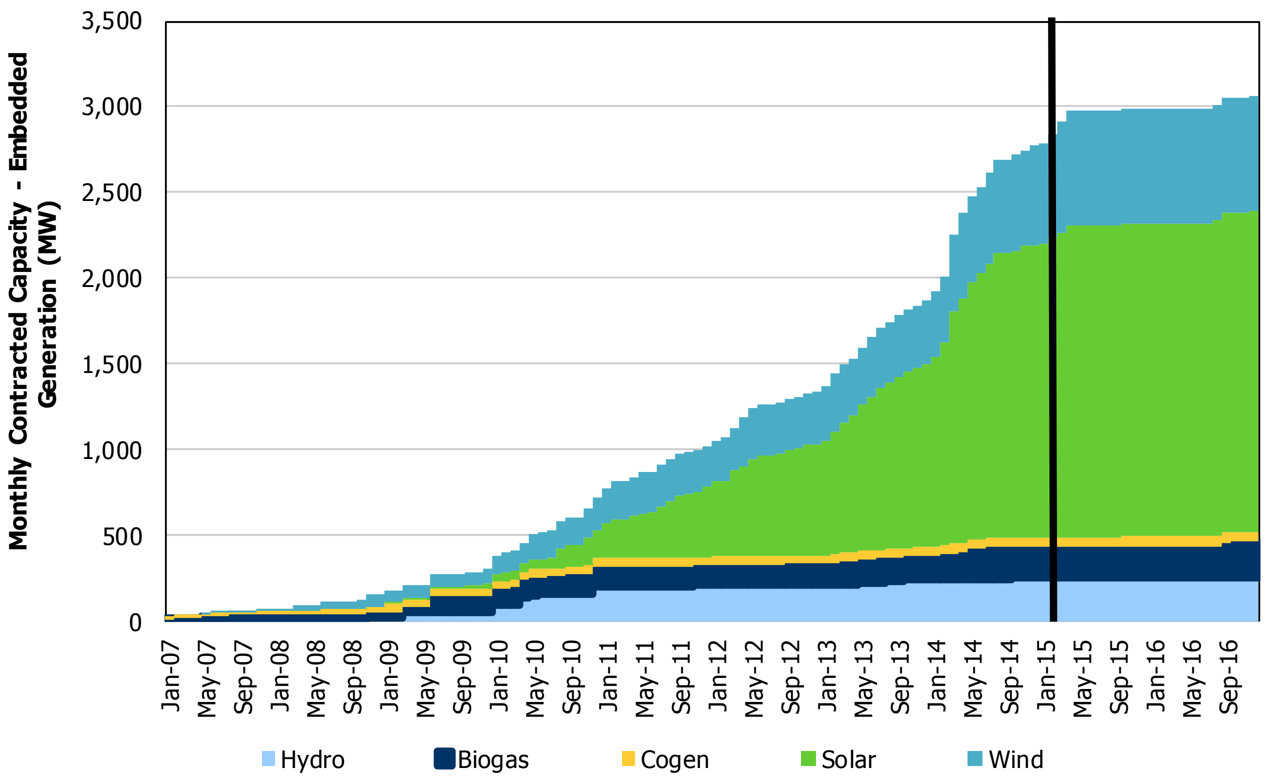
Both TOU and ICI impacts are incorporated into the demand forecast.

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 Micro-FIT program and some generation under the Green Energy Act’s Feed-in Tariff (FIT). 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.

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.

Figure 4.3: Projected Embedded Generation Capacity



Over the course of the 18-Month forecast, the amount of embedded solar installed capacity will range from 1,800 MW to 1,925 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 4.2 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. This trend is expected to continue over the forecast period.

Table 4.2: 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%	0.4%	12.4%	14.2%	20.2%	23.4%	3.2%	0.0%	0.0%	0.0%

- End of Document -

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca
@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/ieso

Independent Electricity System Operator