18-MONTH OUTLOOK

From June 2014 to November 2015

Power to Ontario. On Demand.

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 June 2014 to November 2015 and supersedes the previous forecast released in February 2014.

Economic Outlook

The main economic themes have not varied much within the last few 18-Month Outlook reports. The global economy continues to post modest growth numbers. High debt loads and high unemployment in the developed world leads to slower growth in the emerging economies. Weaker consumer confidence has translated into lower consumption of goods and services, which in turn means lower levels of production in export-dependent emerging economies.

Low borrowing costs have helped fund consumption and business investment, but personal debt loads and consumer confidence have led consumers and businesses to approach increased debt loads and business expansion with caution.

There still exists considerable downside risk as geopolitical events in Ukraine and Syria have the potential to negatively affect the global economy. At the same time, the world's most important commodity – oil – is at near record highs. Increases in the price of oil act as a drag on the economy.

Canada has rather strong domestic fundamentals. We are resource rich, have low interest rates and a healthy financial sector. However, we are also very dependent on trade and are not immune to the state of the global economy. As for Ontario, we are particularly impacted by the state of the U.S. economy. Ontario's economy has seen significant structural change over the last decade. The appreciation of the Canadian dollar, rise of the service sector and the recession have all inherently changed the structure of the economy. The changes are evident in the electric intensity of the economy. While the intensity has dropped significantly since 2005, it has stabilized and should increase slowly going forward as mining and other energy-intensive industries see improving growth.

Over the Outlook period these same issues will determine the growth path of Ontario's economy. Continued low interest rates, robust commodity prices and an improving U.S. and domestic economy will lead to sustained and diverse economic growth.

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 November through April.

Overall, energy demand for the six months was up a robust 3.5% compared to the same months a year earlier. Of course the winter of 2013-14 was particularly cold, so it is very important to adjust for weather. Once weather is accounted for, electricity demand rose a much more modest 0.6% compared to the previous six months. Looking back to a comparable weather corrected period prior to the recession (November 2007 to April 2008) demand is 6.8% lower. The reduction is the combination of economic impacts, conservation and increased embedded generation.

On the positive side, wholesale customers have shown strength since August 2013. For the six month period, their consumption was up 3.7% over the same period a year earlier. The average hourly demand for the wholesale customers was 2,025 MW in April 2014, which is a 120 MW increase over the previous April. The increases came primarily from Mining, Iron & Steel Manufacturing and Chemicals.

Overall, the weather for the period was colder than normal. All the months except April were colder than normal. The total the weather correction for the six months was 1.4 TWh.

The 2013-14 winter peak demand occurred on January 7th, which was part of the cold snap that started 2014. The afternoon high was -17.4°C. The peak demand was 22,744 MW (22,119 MW weather-corrected). At the time of the peak there was 0.01 MW of demand measures dispatched off. The actual peak was higher than the previous winter's, but the weather corrected value was lower.

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. The Ontario Power Authority (OPA) and local distribution companies (LDCs) will be the organizations driving these impacts through their program offerings. In the 18-Month Outlook, the impacts of conservation and embedded generation are decremented from demand, whereas demand response programs are included in our analysis as a resource under the category of demand measures. The estimated impacts stemming from the Industrial Conservation Initiative (ICI) is decremented from the forecast. Conservation, embedded generation, demand response and the global adjustment 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. Winter peaks will face downward pressure from gains in lighting efficiency. Summer peaks will face greater downward pressure from numerous sources - air conditioning efficiency, ICI impacts and solar embedded generation.

Grid supplied energy demand is expected to show a small increase in 2014 before decreasing in 2015.

Table 1: Peak and Energy Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2014	22,949	24,855
Winter 2014-15	22,273	23,219
Summer 2015	22,726	24,567
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 (Forecast)	140.7	0.2%
2015 Energy (Forecast)	139.7	-0.7%

- 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 June 2014 to November 2015. It supersedes the previous forecast released in February 2014 and the previous Ontario Demand Forecast document released in December 2013.

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_2014june.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_2014june.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.

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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 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.

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)
08-Jun-14	19,927	23,347	1,248	2,631	08-Mar-15	19,646	20,439	661	2,810
15-Jun-14	20,888	23,795	996	2,678	15-Mar-15	18,612	19,586	789	2,719
22-Jun-14	21,757	24,066	761	2,758	22-Mar-15	18,054	18,771	728	2,632
29-Jun-14	22,470	24,252	719	2,767	29-Mar-15	18,111	19,230	667	2,635
06-Jul-14	22,586	24,007	1,097	2,674	05-Apr-15	17,916	18,544	580	2,547
13-Jul-14	22,949	24,855	890	2,756	12-Apr-15	17,309	18,212	598	2,515
20-Jul-14	22,789	23,770	938	2,709	19-Apr-15	16,674	17,155	495	2,468
27-Jul-14	22,152	24,107	1,126	2,785	26-Apr-15	16,438	16,797	645	2,438
03-Aug-14	22,078	24,246	988	2,786	03-May-15	17,270	19,694	829	2,425
10-Aug-14	21,403	24,438	1,038	2,689	10-May-15	17,464	20,042	814	2,412
17-Aug-14	21,295	23,849	1,077	2,695	17-May-15	18,399	21,623	753	2,440
24-Aug-14	21,270	23,559	1,456	2,741	24-May-15	18,768	21,808	1,108	2,396
31-Aug-14	20,179	22,851	1,497	2,633	31-May-15	19,285	21,475	1,262	2,450
07-Sep-14	18,933	22,336	1,540	2,462	07-Jun-15	19,643	23,180	1,253	2,621
14-Sep-14	18,779	21,014	785	2,491	14-Jun-15	20,811	23,593	1,017	2,652
21-Sep-14	18,608	19,766	901	2,519	21-Jun-15	21,595	24,041	788	2,696
28-Sep-14	17,756	18,052	519	2,470	28-Jun-15	22,359	24,034	733	2,765
05-Oct-14	17,028	17,496	453	2,483	05-Jul-15	22,398	23,772	1,100	2,701
12-Oct-14	17,307	17,721	648	2,502	12-Jul-15	22,726	24,567	896	2,761
19-Oct-14	17,963	18,319	434	2,468	19-Jul-15	22,529	23,656	943	2,659
26-Oct-14	17,873	18,387	392	2,570	26-Jul-15	22,049	24,028	1,122	2,767
02-Nov-14	18,589	18,971	190	2,615	02-Aug-15	21,912	24,079	1,001	2,755
09-Nov-14	18,791	19,521	384	2,643	09-Aug-15	21,279	24,285	1,080	2,711
16-Nov-14	19,364	19,985	565	2,721	16-Aug-15	21,192	23,783	1,120	2,699
23-Nov-14	19,851	20,654	300	2,762	23-Aug-15	21,139	23,420	1,497	2,725
30-Nov-14	20,336	21,487	591	2,817	30-Aug-15	19,976	22,667	1,535	2,607
07-Dec-14	21,055	22,086	202	2,909	06-Sep-15	18,273	21,776	1,589	2,501
14-Dec-14	20,833	22,076	385	2,905	13-Sep-15	18,026	20,515	676	2,461
21-Dec-14	21,151	22,362	496	2,943	20-Sep-15	17,740	19,872	912	2,494
28-Dec-14	20,254	21,241	202	2,766	27-Sep-15	16,899	18,103	570	2,449
04-Jan-15	20,517	21,350	298	2,835	04-Oct-15	17,012	17,394	810	2,481
11-Jan-15	22,272	23,219	484	3,030	11-Oct-15	17,037	17,432	709	2,502
18-Jan-15	21,615	22,431	466	2,984	18-Oct-15	17,576	17,952	530	2,459
25-Jan-15	21,746	22,431	367	2,986	25-Oct-15	17,544	18,085	367	2,547
01-Feb-15	21,744	22,405	301	3,013	01-Nov-15	18,061	18,481	220	2,581
08-Feb-15	20,926	21,936	729	2,959	08-Nov-15	18,809	19,146	405	2,647
15-Feb-15	20,315	21,750	703	2,879	15-Nov-15	19,078	19,790	551	2,672
22-Feb-15	20,118	21,698	521	2,840	22-Nov-15	19,648	20,440	306	2,752
01-Mar-15	20,671	21,603	474	2,906	29-Nov-15	20,103	21,072	553	2,794

Compared to the previous forecast, the peaks and energy are slightly higher during the winter and slightly less during the summer. Figures 2.1 and 2.2 show the projected energy and peak demand for the outlook period.

Figure 2.1: Weekly Energy Demand – History and Forecast

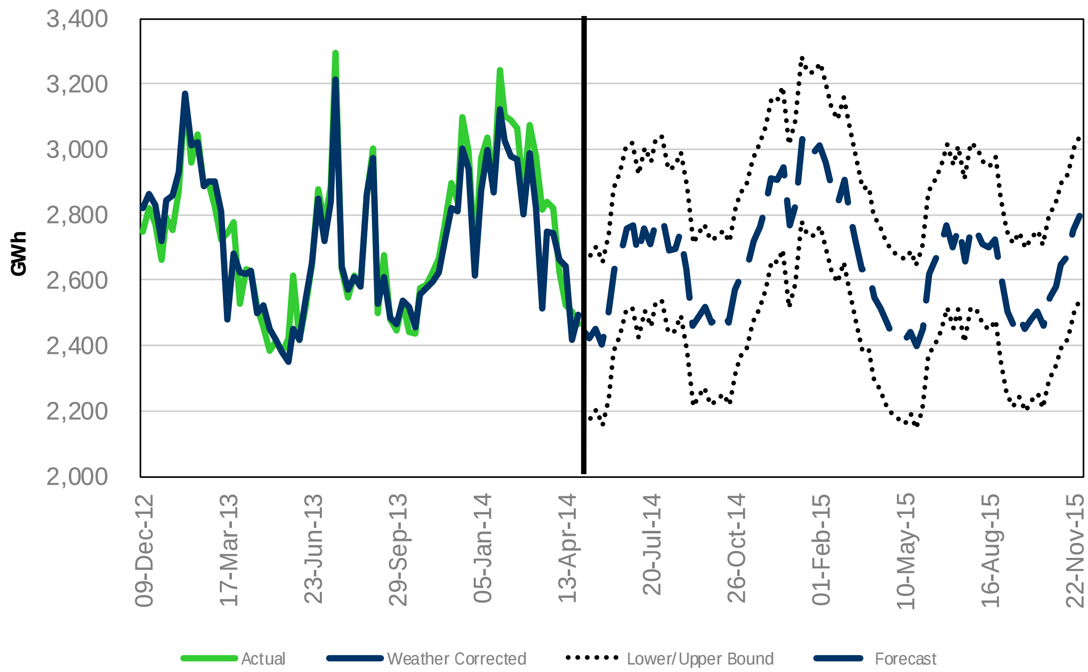
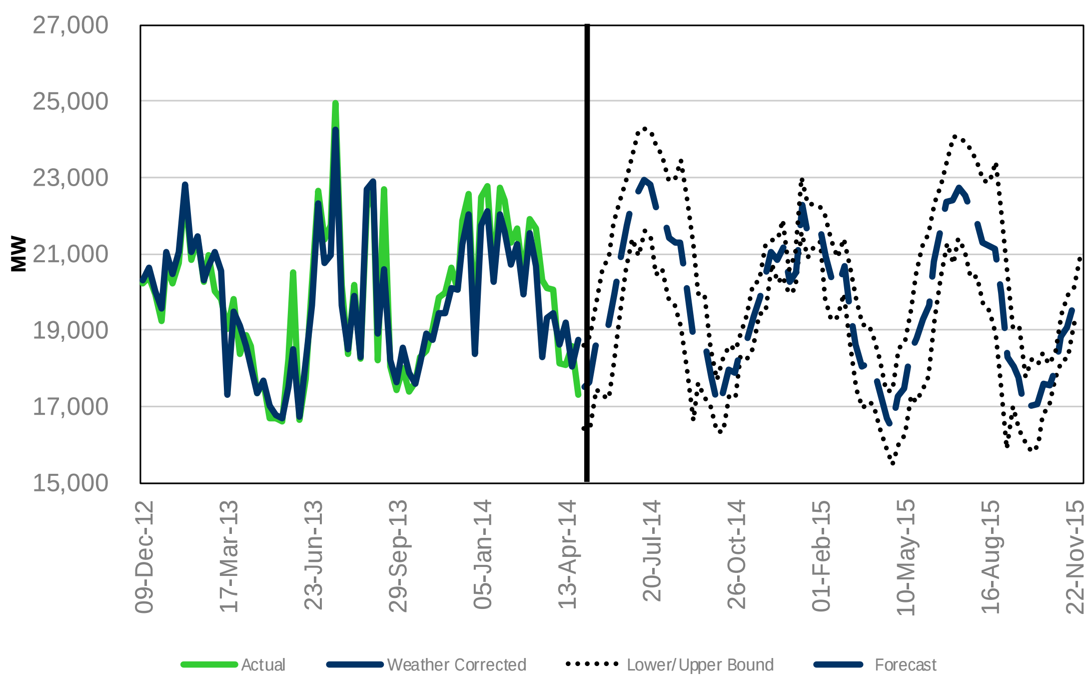


Figure 2.2: Weekly Peak Demand – History and Forecast



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3.0 Historical Review

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

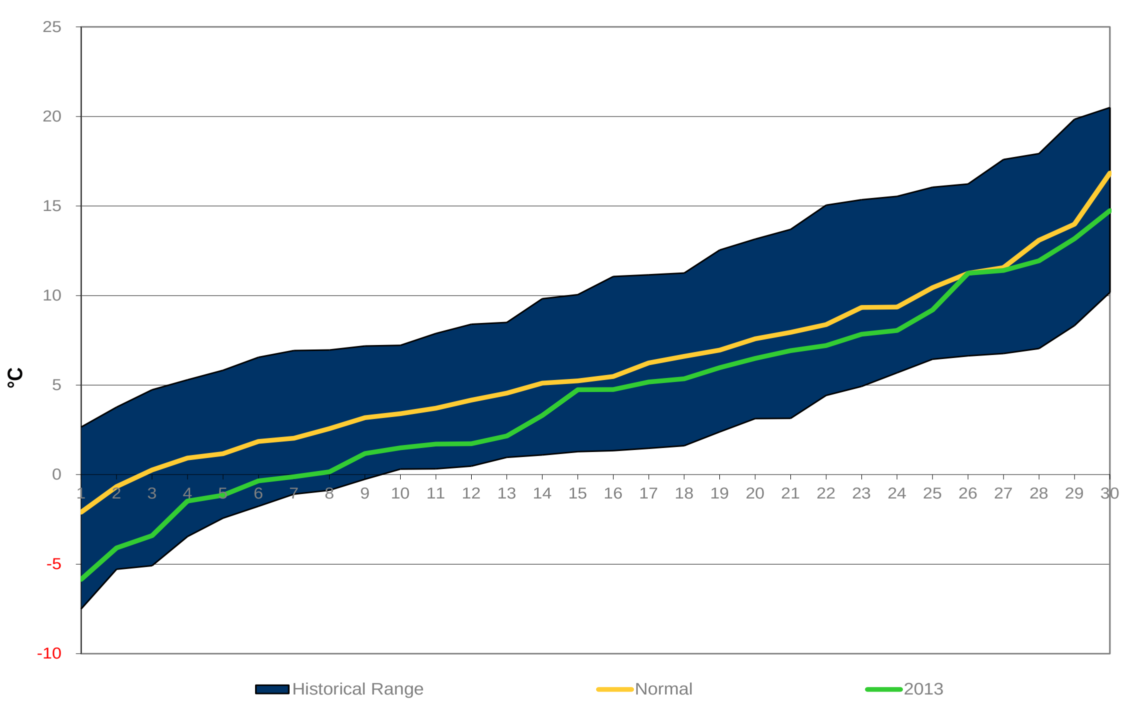
3.1 Six Month Review – November to April

Since the last Ontario Demand document, actuals have been recorded for the period November to April. The winter of 2013-14 was colder 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 the 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.

November

- November's weather was colder than normal. The peak occurred on November 28th which was the coldest weekday of the month. The following figure shows the afternoon high temperature for November 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 for the past 31 years. The graph shows that the temperature for November 2013 was consistently below normal (the yellow line) and the colder days of the month were significantly lower.

Figure 3.1: Daily Temperature - November



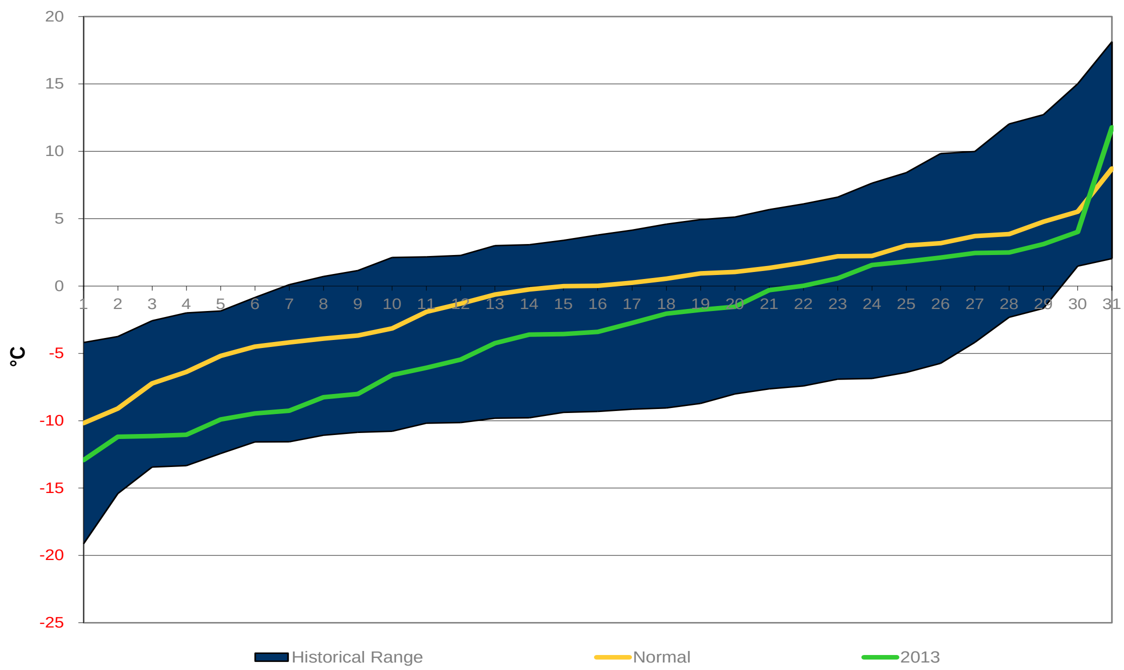
- The 20,615 MW peak was the highest post-recessionary peak for November. The weather corrected peak was lower at 20,086 MW and is consistent with recent experience. Prior to the recession, November peaks were in the range of 21,000 to 22,000 MW but, since the recession, have fallen to in the 19,000 to 20,000 MW range.

- Energy demand for the month was the highest it has been in over 3 years. Demand was 11.6 TWh (weather corrected was 11.4 TWh).
- Minimum demand (11,571 MW) was lower than the previous November.
- Wholesale industrial consumption was 3.0% higher than November 2012.

December

- December was colder than normal. The peak did occur on the coldest weekday. December peaks can be erratic due to the impact of the holidays later in the month when most of the colder weather occurs. The following figure shows the ranked temperatures for the month. Other than the warmest day, it was colder than normal.

Figure 3.2: Daily Temperature - December

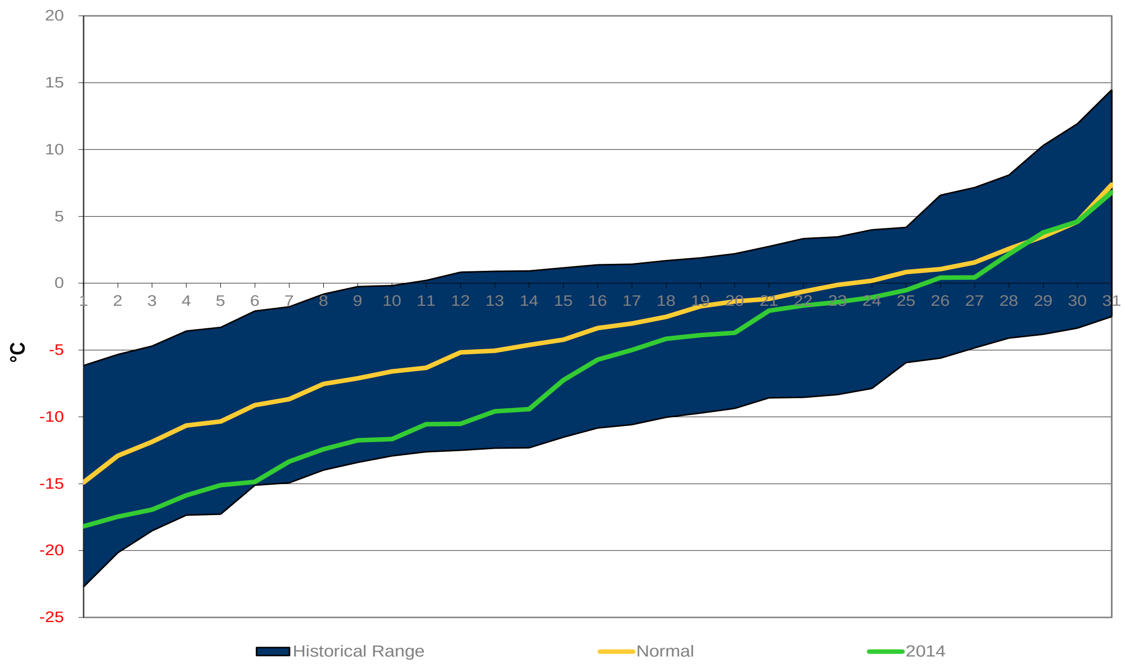


- The actual peak of 22,556 MW was the highest since December 2007. The weather corrected figure came in at 22,047 MW, which is the highest since December 2009.
- Energy demand for the month was 12.8 TWh (actual) and 12.5 TWh (weather corrected), which are consistent with Decembers since the recession.
- Minimum demand (12,626 MW) was lower than the previous December. Despite the lost load during the ice storm, the minimum load occurred a week later between Christmas and New Year’s Day.
- Wholesale industrial consumption was 4.5% higher than December 2012.

January

- The weather for January was much colder than normal. The peak did not occur on the coldest two days, as those days fell on New Year's Day and shortly after. The peak occurred on the third coldest day. The following figure shows the ranked temperature for the month. Once again, it is evident that the month was colder than normal.

Figure 3.3: Daily Temperature - January

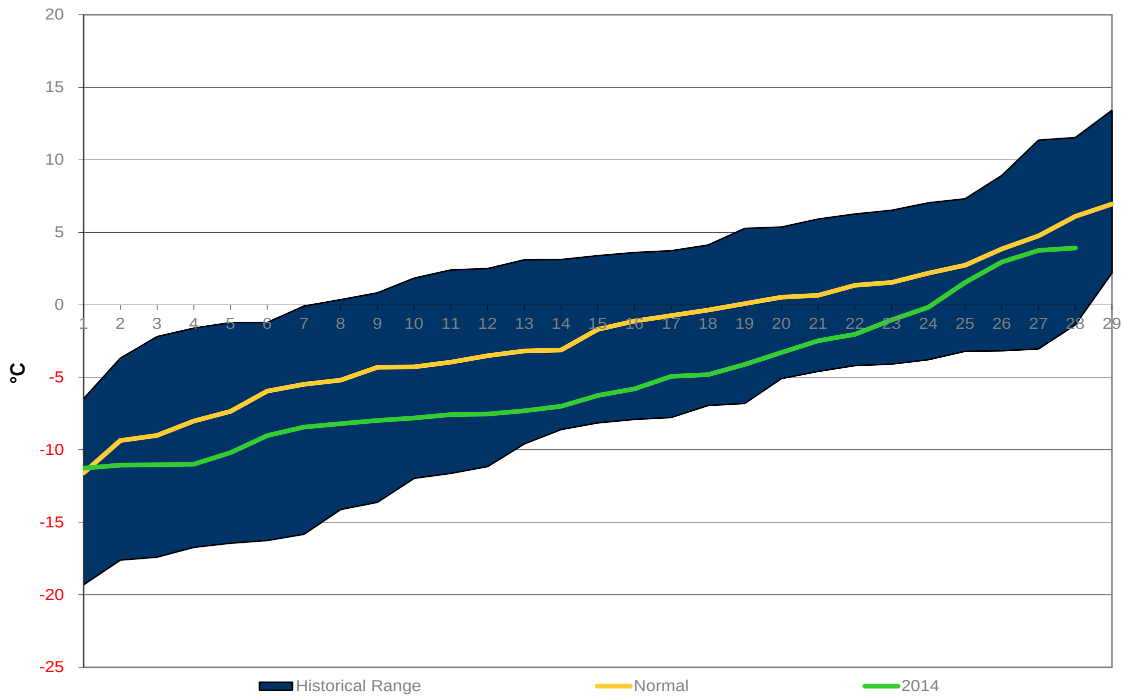


- The January peak was 22,744 MW and 22,119 MW weather corrected. The actual was the highest since January 2008 whereas the weather corrected was a reduction from last January.
- Energy demand for the month was 13.6 TWh and 13.3 TWh weather corrected. Both energy levels were the highest since January 2009.
- Minimum demand was 13,381 MW which was the highest since January 2009. The minimum is from a Sunday during a brief mild spell.
- Wholesale industrial energy demand was 0.1% higher than January 2013. This was the weakest monthly growth over the six month period.

February

- The weather for February was once again colder than normal. The peak occurred during a cold snap at the end of February. The peak did not occur on the coldest day but the second coldest day. The following figure shows the ranked temperature weather for February. Other than the coldest day, the temperature was colder than normal.

Figure 3.4: Daily Temperature - February

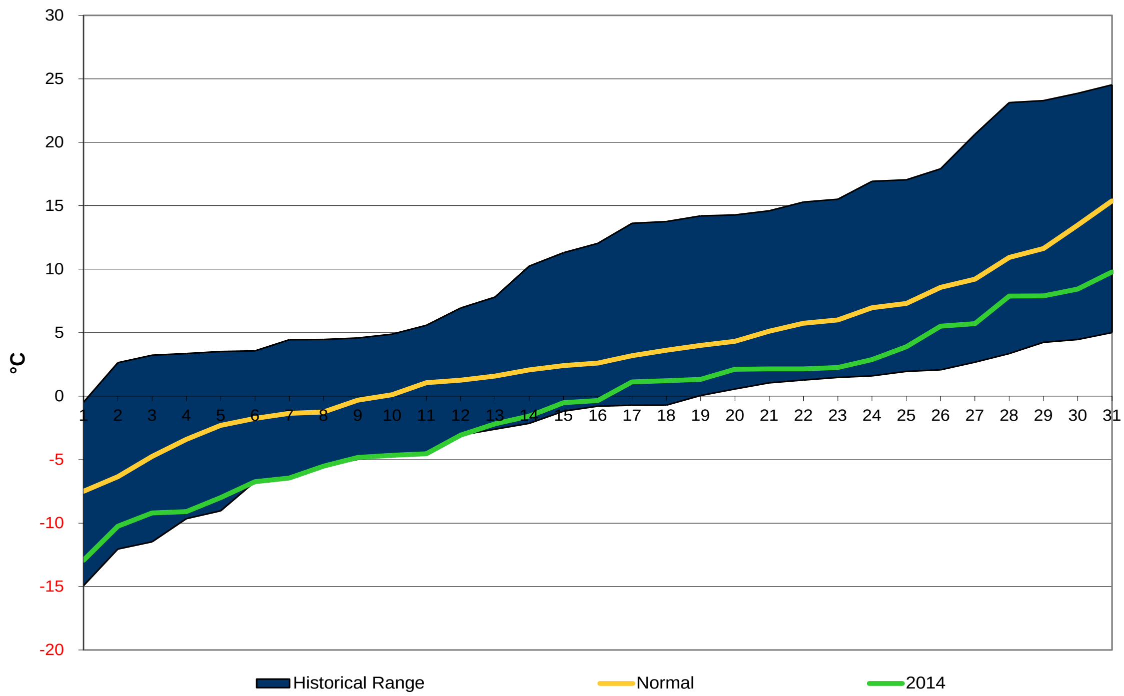


- The actual peak of 21,905 MW was the highest February peak since 2009. After weather correction, the peak was a more modest 21,541 MW which was only 90 MW higher than last February's value.
- Energy demand for the month was 12.1 TWh, which was the highest since February 2008. Again, the weather had much to do with the high numbers, as the weather corrected value was 11.7 TWh, a slight increase on February 2013.
- Minimum demand for the month was 13,981 MW, which is the highest since pre-recession February 2008. This again is attributable to the cold weather. The minimum occurred on a Sunday during a mild spell.
- Wholesale customers' consumption increased by 1.1% over the previous February.

<u>March</u>

- Continuing the theme for the winter, March was much colder than normal. The peak occurred on the coldest day of the month. The following figure shows the ranked temperature for the month. The graph shows illustrates that of all the months March had the greatest deviation from normal.

Figure 3.5: Daily Temperature - March

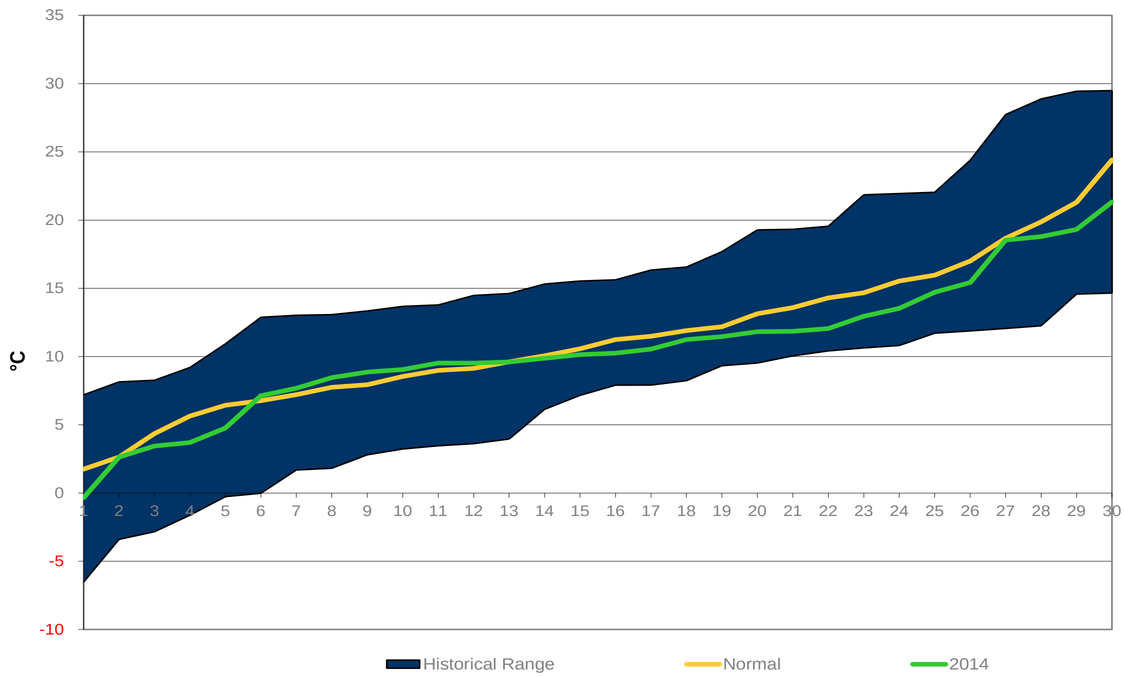


- The month's peak demand of 21,656 MW was the highest since March 2007 which had similar peak weather. The weather corrected value of 20,654 MW was a slight increase over March 2013.
- The minimum demand of 13,296 MW is very high and reflects the cold temperatures during the month. This was the highest minimum since March 2008.
- Wholesale customers' consumption growth rebounded in March posting a 7.2% increase over the previous March.

<u>April</u>

- The weather for April was fairly normal. The peak for April can be either the result of either cold or hot weather. For April 2014, the peak was a cold weather peak as it occurred on the coldest day. The following figure shows the ranked temperature for the month.

Figure 3.6: Daily Temperature - April



- The actual peak of 18,557 MW (18,476 MW weather corrected) is fairly consistent with the April values since the recession. Both the actual and the weather corrected values were a small decline from the previous year.
- Actual and weather corrected energy demand were both 10.8 TWh, a decline from last April were demand was 10.9 TWh (both actual and weather corrected).
- Minimum demand of 11,944 MW was an increase over April 2013.
- Wholesale customers' consumption growth followed up a strong showing in March with another strong month in April. Consumption was up 6.3% over April 2013.

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. Figure 3.1 shows the average daily high temperature by month for 2013-4 compared to the history for 1970-2011.

Table 3.1: Historical 2013-2014 Weather and Demand Summary

Historical Analysis		November	December	January	February	March	April
Actual Weather	Average Temperature (°C)	4.7	-2.1	-6.0	-5.1	-0.3	10.3
	Minimum Temperature (°C)	-5.2	-11.7	-17.9	-12.2	-12.1	-0.9
	Maximum Temperature (°C)	15.6	15.2	7.4	4.9	11.0	22.2
Normal Weather	Normal Average Temperature (°C)	6.7	0.2	-3.3	-1.5	3.6	10.7
	Normal Minimum Temperature (°C)	-2.0	-8.4	-13.5	-13.5	-5.5	2.8
	Normal Maximum Temperature (°C)	18.9	10.0	6.7	8.2	16.7	25.0
Actual Demand	Peak Demand (MW)	20,615	22,556	22,774	21,905	21,656	18,557
	Average Hour (MW)	16,168	17,211	18,298	17,957	17,032	15,051
	Minimum Hour (MW)	11,571	12,626	13,381	13,981	13,296	11,944
	90th Percentile (MW)	18,660	19,937	20,876	20,113	19,185	17,048
	Percent above 20,000 (MW)	1.2%	8.9%	23.1%	11.3%	3.5%	0.0%
	# of Hours Above 20,000 (MW)	9	66	172	76	26	0
	Energy Demand (GWh)	11,641	12,805	13,614	12,067	12,672	10,837
Weather Corrected Demand	Peak Demand (MW)	20,086	22,047	22,119	21,541	20,654	18,476
	Energy Demand (GWh)	11,740	12,532	13,302	11,727	11,983	10,933
Forecast Demand	Peak Demand (MW)	20,326	21,395	22,320	20,964	19,906	17,649
	Energy Demand (GWh)	11,687	12,700	13,356	11,748	12,055	10,731

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 November 2013 to April 2014 was up 3.5% over the same period a year earlier. However, much of the increase was attributable to the colder than normal winter weather. After adjusting demand for weather, the growth rate was a more modest 0.6%.

Underneath this overall demand growth are two fairly different trends at the consumer level. These trends have been around for the past couple of years and the past six months – November 2013 to April 2014 – continued to display them. On one side, wholesale customers' load has increased by 3.7% over the same period a year prior. On the other side, distributors' loads have increased by 3.1%. However, that growth is inflated as distributor loads are very weather sensitive and the growth is a result of the cold winter. After adjusting for weather, the distributors' loads showed a reduction of 0.3% compared to the same period a year earlier. Although the distributors do have industrial loads and would see a similar industrial revival as the wholesale customers have experienced, distributors would be subject to the vast majority of the conservation and embedded generation impacts.

Figure 3.2 shows the year-over-year change in wholesale customers' average hourly consumption. The graph illustrates the modest improvements since a weak 2011. Structural change in the economy has had a variety of impacts across the various industrial sectors.

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

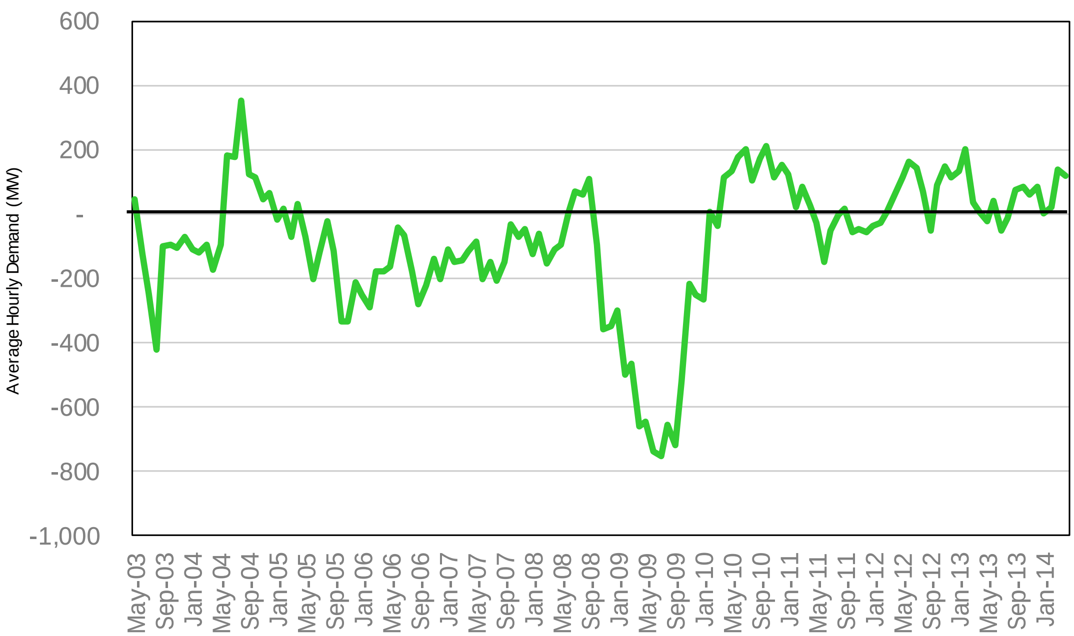


Figure 3.8: Wholesale Customers' Average Hourly Consumption by Industry Segment

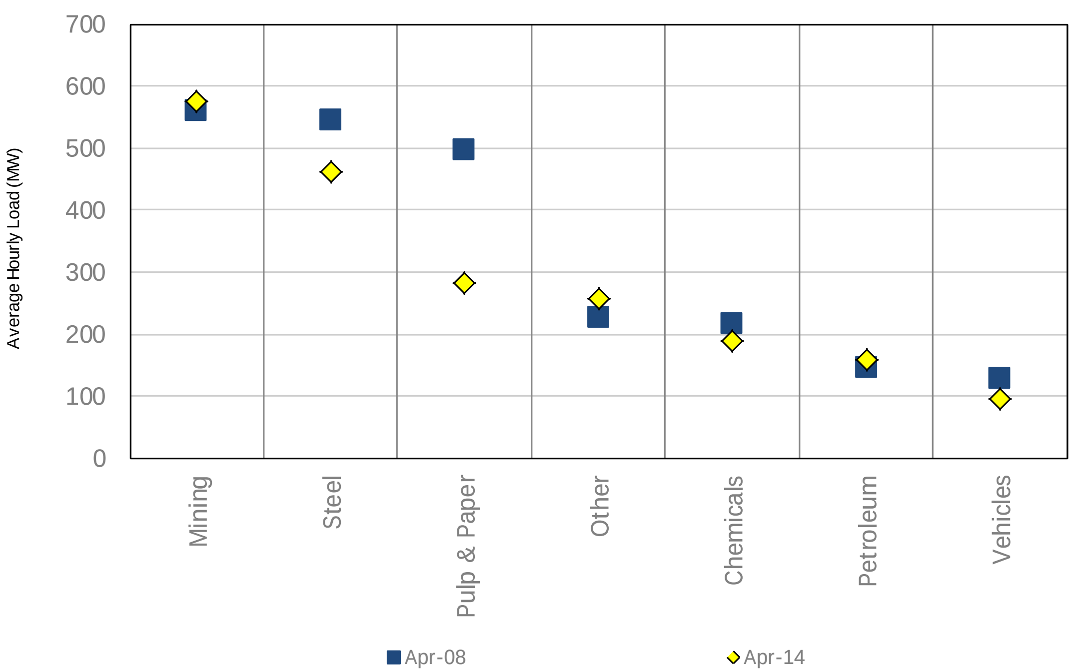


Figure 3.3 shows the wholesale customers' average hourly load by industry segment for the six month period compared to the same six months prior to the recession (November 2007 to April

2008). The graph highlights the lost loads in the Pulp & Paper and Steel sectors. The other sectors are fairly close to their pre-recession levels.

The Pulp & Paper sector was at one point the industrial segment with the largest electricity consumption. 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 2.5 TWh in 2013. Mining is now the largest electricity consuming segment. With the "Ring of Fire" development, it will undoubtedly remain the highest consuming segment.

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 3.4 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 4.2 TWh in 2013, 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

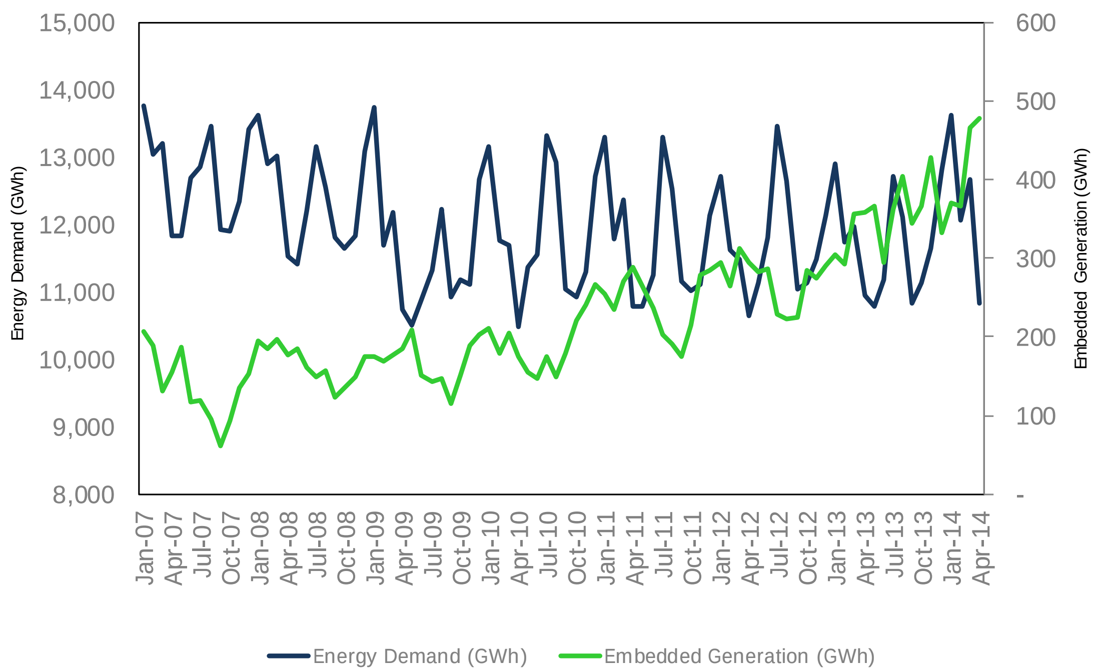


Table 3.2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week, and notes any item of significance for the week. If the weather-corrected demand is greater than the actual demand, it means that the actual weather was milder than 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
45	10-Nov-13	29-Oct-13	2,623	2,597	
46	17-Nov-13	04-Nov-13	2,667	2,621	Remembrance Day
47	24-Nov-13	12-Nov-13	2,778	2,724	
48	01-Dec-13	24-Nov-13	2,895	2,820	
49	08-Dec-13	28-Nov-13	2,840	2,811	
50	15-Dec-13	03-Dec-13	3,099	3,003	
51	22-Dec-13	14-Dec-13	2,994	2,940	Ice Storm
52	29-Dec-13	16-Dec-13	2,672	2,615	Christmas Day & Boxing Day
1	05-Jan-14	24-Dec-13	2,975	2,871	New Year's Day
2	12-Jan-14	02-Jan-14	3,035	2,998	
3	19-Jan-14	07-Jan-14	2,888	2,867	
4	26-Jan-14	15-Jan-14	3,243	3,120	
5	02-Feb-14	22-Jan-14	3,105	3,024	
6	09-Feb-14	28-Jan-14	3,089	2,977	
7	16-Feb-14	05-Feb-14	3,066	2,970	
8	23-Feb-14	11-Feb-14	2,868	2,802	Family Day
9	02-Mar-14	18-Feb-14	3,073	2,987	
10	09-Mar-14	27-Feb-14	2,978	2,819	
11	16-Mar-14	03-Mar-14	2,816	2,514	
12	23-Mar-14	12-Mar-14	2,837	2,748	
13	30-Mar-14	17-Mar-14	2,820	2,743	
14	06-Apr-14	26-Mar-14	2,623	2,661	
15	13-Apr-14	03-Apr-14	2,521	2,645	
16	20-Apr-14	07-Apr-14	2,503	2,416	Good Friday
17	27-Apr-14	15-Apr-14	2,467	2,492	Easter Monday

3.3 Historical Peak Demand

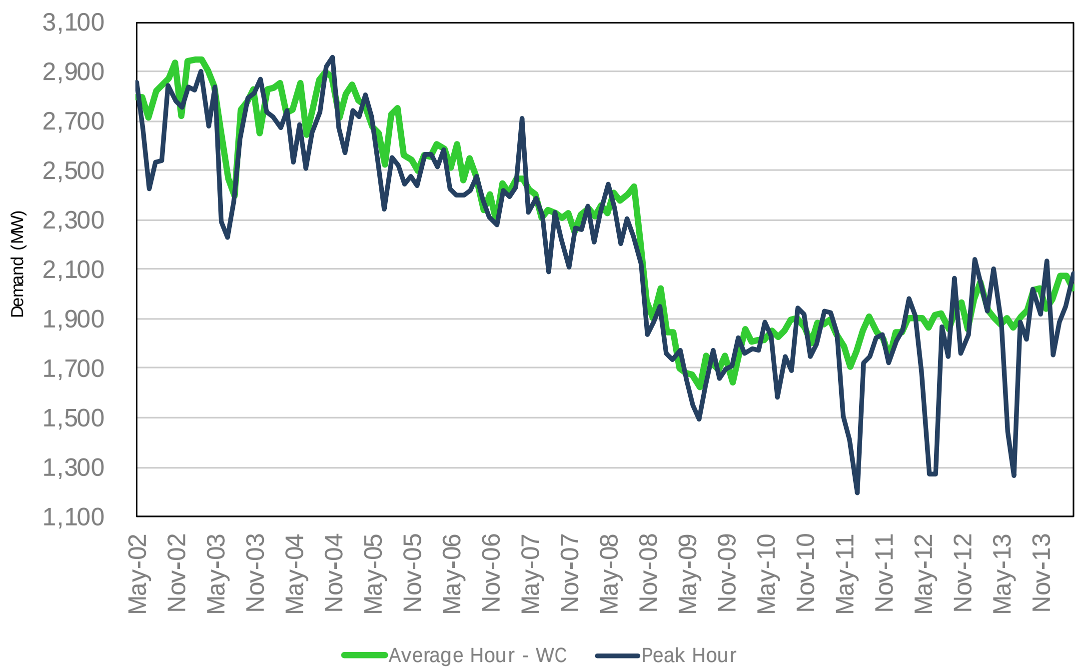
Peak demands are weather-driven, weekday events. Peak demands have been facing downward pressure due to a number of factors. Conservation, time of use rates, embedded generation, demand response, the Industrial Conservation Initiative (ICI) and lower levels of economic activity have all contributed to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

The winter peak was 22,774 MW, which was higher than last winter's peak (22,610 MW). However, on a weather-corrected basis, it was lower than last winter's – 22,119 MW versus 22,808 MW. At the time of this winter's peak, there was 0.01 MW of demand response, whereas last winter's peak had 3.5 MW of demand response. This is not unusual as demand measures are more frequently utilized during the summer. The winter peaks do not face the same downward pressure that summer peaks do. Summer peak conservation savings come from improvements in air conditioning efficiency, and winter peak conservation savings come from improvements in lighting efficiency. The vast majority of embedded generation is solar powered. Solar generation will be high during the summer peaks as they occur in the afternoon. Winter peaks occur after sunset and will, therefore, not be impacted by embedded solar. To date, the five peak days for the ICI have all occurred in the summer, therefore, the winter peaks have not observed much ICI impacts.

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 it.

Figure 3.5 shows the wholesale customers' consumption at the time of the monthly peak and the average hourly consumption for the month. The graph clearly shows the economic impact on consumption starting with the financial meltdown in September 2008. It is also important to note that historically the average and peak demands were highly correlated. In 2011, with the introduction of the Global Adjustment Allocation (GAA) – now the ICI - there is divergence between the average and monthly peaks during the summer months when the top five peaks occur. Class A customers are reducing demand during peak summer hours as a result of the GAA / ICI. Estimating the impacts can be complicated as the ICI relies on Class A customers correctly identifying the five peak days. This can lead to additional reductions on days that do not turn out to be top five days. Since the time horizon for the ICI is May to April, participants would know the top 5 peaks from the summer and would not be hedging during the winter unless the peak was getting close to the 5 peaks from the previous summer. This winter's peak demand ranked as the 7th highest peak.

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



In addition to the ICI, time of use rates have an impact on peak demand as consumers are incited to shift demand to "off peak" periods. This also has an impact on both winter and summer peaks.

Figure 3.6 shows the break down for the summer 2013 peak, which occurred on July 17th during hour 17 EST. The actual recorded peak demand recorded was 24,794 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 (94 MW), embedded generation (548 MW) and ICI impacts (916 MW). This analysis does not show the impact of conservation, which also would have contributed to higher reconstituted demand number.

Figure 3.12: Anatomy of a Summer Peak

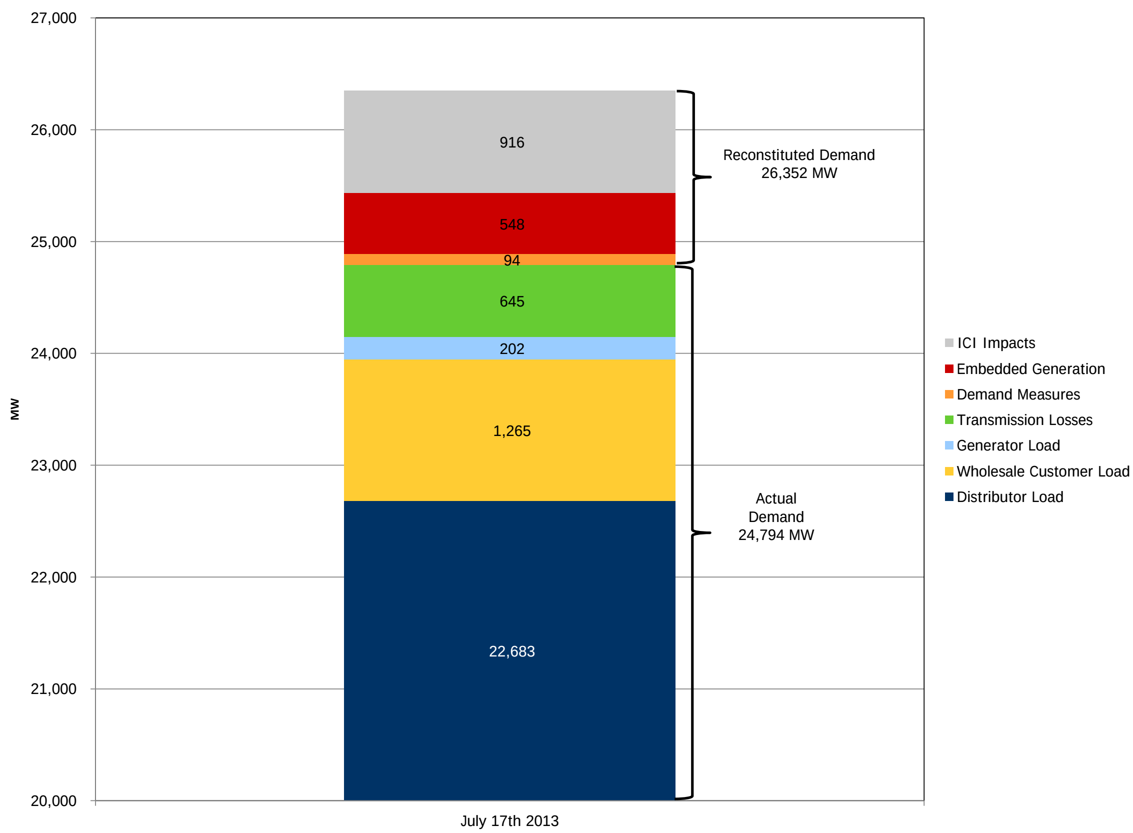


Table 3.3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3.3: Historic Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
18	05-May-13	24-Apr-13	16,697	17,002	12.3
44	03-Nov-13	24-Oct-13	18,445	18,888	8.3
45	10-Nov-13	29-Oct-13	19,028	18,734	6.6
46	17-Nov-13	04-Nov-13	19,835	19,427	5.2
47	24-Nov-13	12-Nov-13	19,971	19,453	0.5
48	01-Dec-13	24-Nov-13	20,615	20,086	-5.2
49	08-Dec-13	28-Nov-13	20,055	20,062	-3.3
50	15-Dec-13	03-Dec-13	21,881	21,239	3.2
51	22-Dec-13	14-Dec-13	22,556	22,047	-11.7
52	29-Dec-13	16-Dec-13	18,980	18,355	-8.3
53	05-Jan-14	24-Dec-13	22,476	21,752	-9.9
54	12-Jan-14	02-Jan-14	22,774	22,119	-17.9
55	19-Jan-14	07-Jan-14	20,346	20,262	-17.4
56	26-Jan-14	15-Jan-14	22,737	22,036	-1.2
57	02-Feb-14	22-Jan-14	22,383	21,586	-14.4
58	09-Feb-14	28-Jan-14	21,268	20,699	-12.8
59	16-Feb-14	05-Feb-14	21,678	21,264	-6.8
60	23-Feb-14	11-Feb-14	20,358	19,940	-10.2
61	02-Mar-14	18-Feb-14	21,905	21,541	-1.6
62	09-Mar-14	27-Feb-14	21,656	20,654	-12.2
63	16-Mar-14	03-Mar-14	20,318	18,290	-12.1
64	23-Mar-14	12-Mar-14	20,103	19,331	-4.5
65	30-Mar-14	17-Mar-14	20,043	19,432	-4.5
66	06-Apr-14	26-Mar-14	18,131	18,604	-5.1
67	13-Apr-14	03-Apr-14	18,084	19,172	3.4
68	20-Apr-14	07-Apr-14	18,557	18,025	9.1
69	27-Apr-14	15-Apr-14	17,310	18,727	-0.9

3.4 Load Duration Curves

The following load duration curves display load for the four seasons. The seasons are defined as fall (September, October and November), winter (December, January and February), spring (March, April and May) and summer (June, July and August). The following graphs are presented in reverse order with the most recent data (winter) first (Figures 3.13 to 3.16).

The figures are not weather-corrected so the weather will influence the shape of each of the graphs. The impact of the colder than normal winter weather can be seen in the load duration curve. Likewise, the warmer than normal summer weather is very evident in the summer 2013 load duration curve.

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 3.13: Winter Load Duration Curve

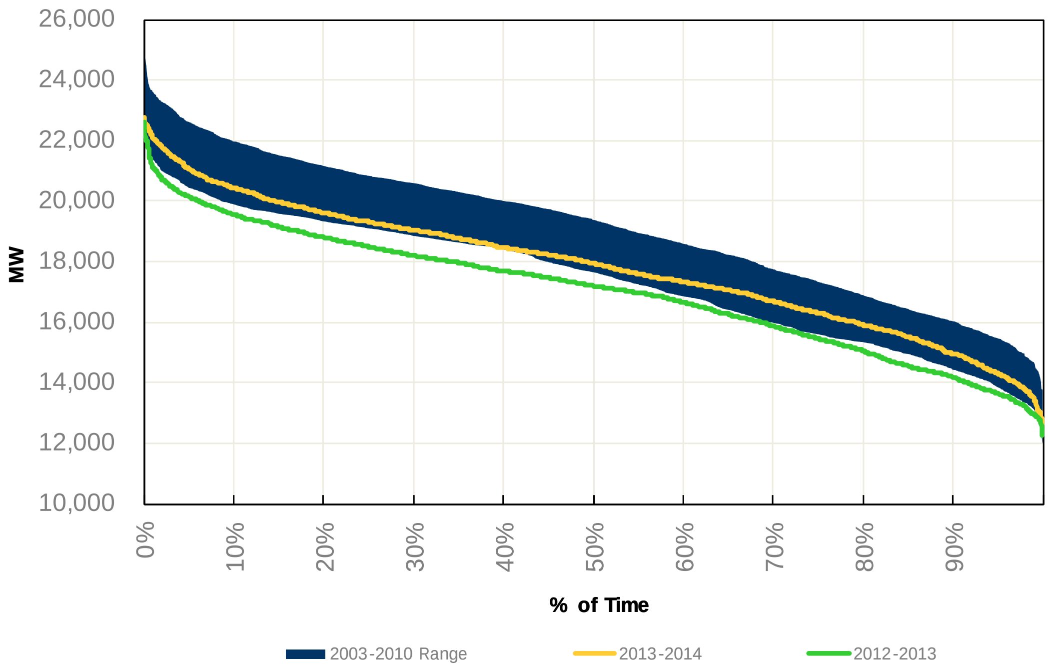


Figure 3.14: Fall Load Duration Curve

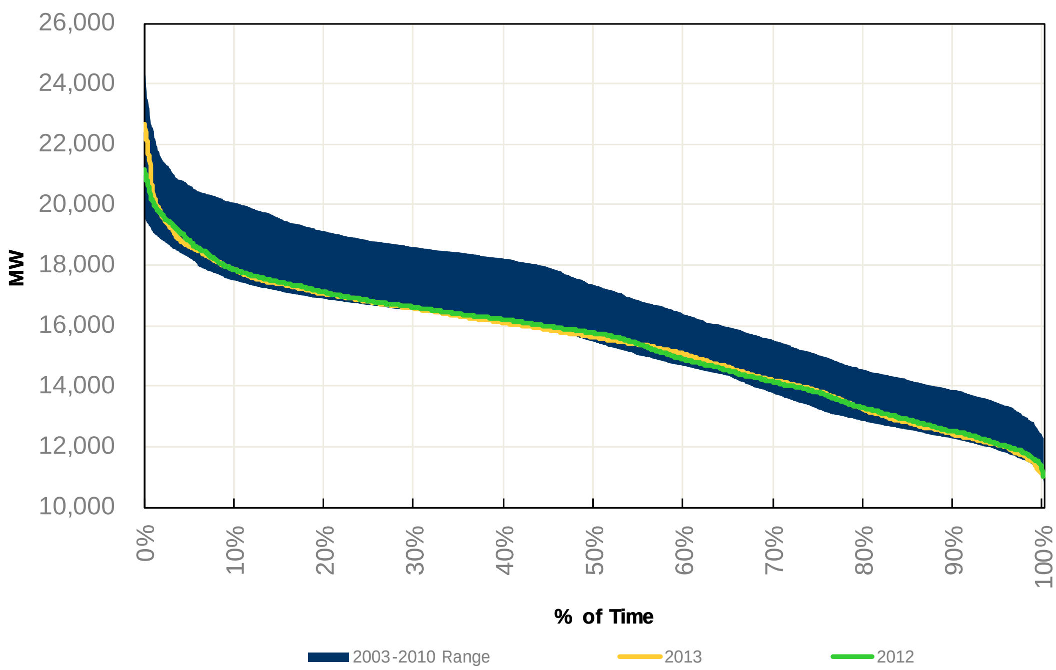


Figure 3.15: Summer Load Duration Curve

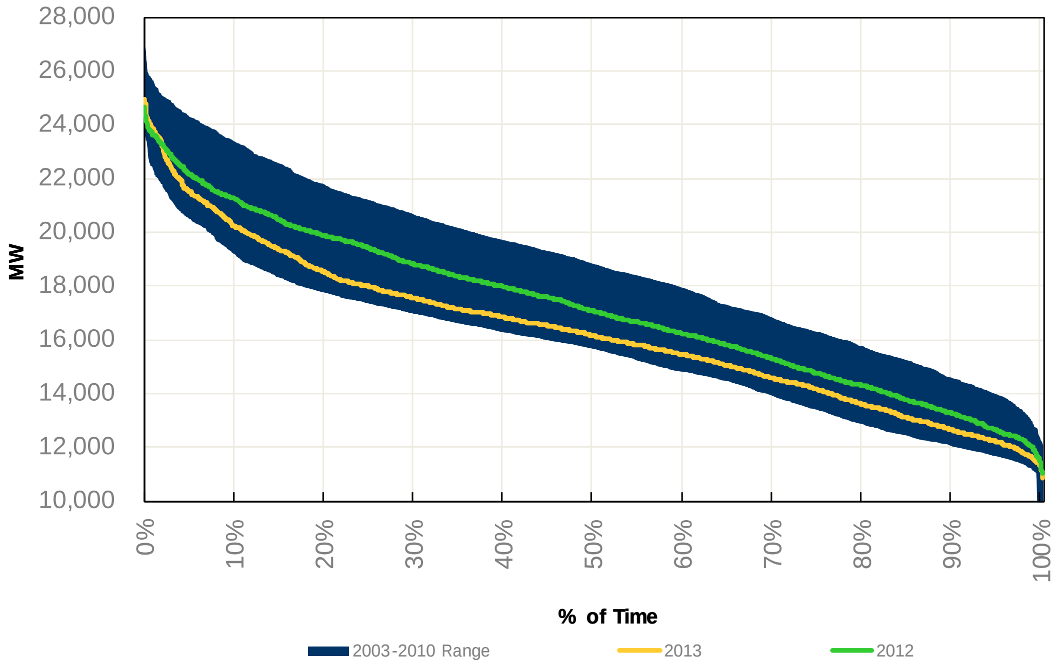
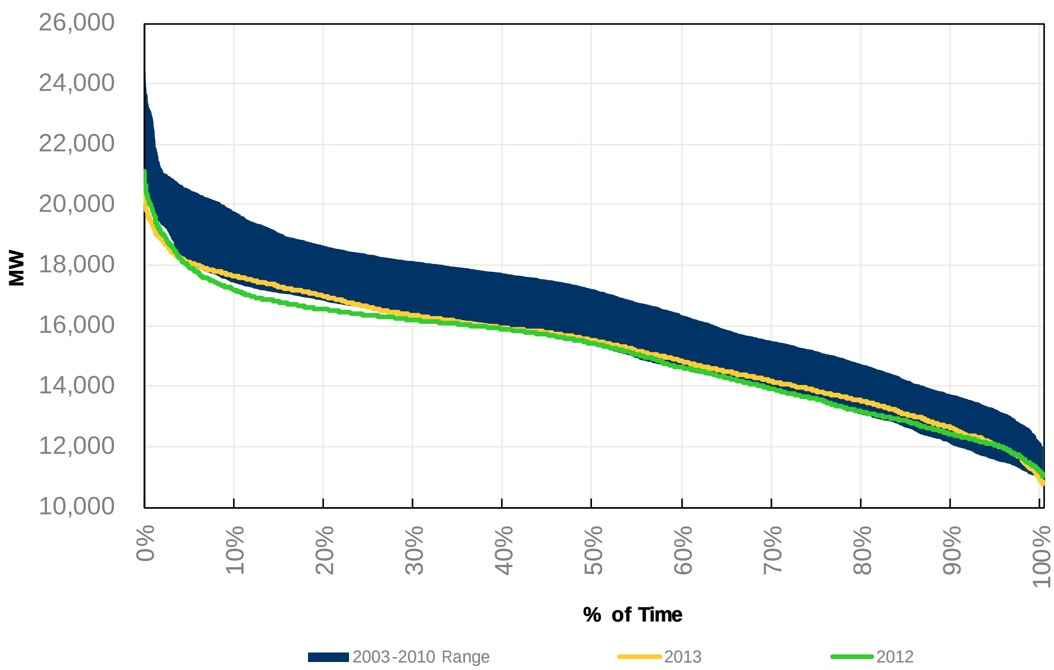


Figure 3.16: Spring Load Duration Curve



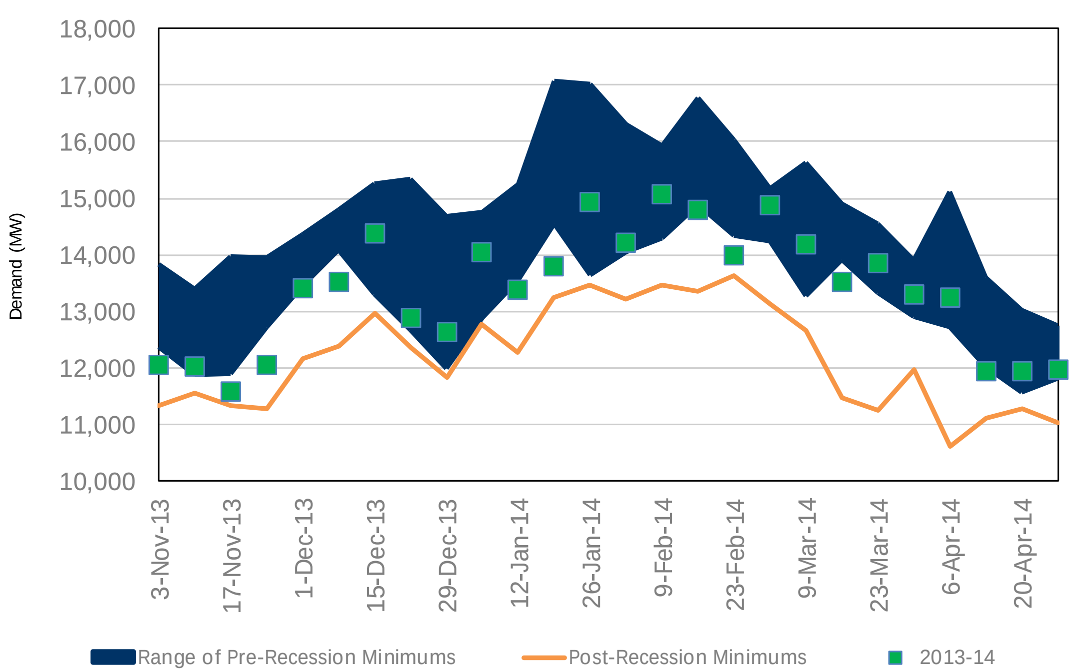
3.5 Historical Minimum Demand

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 shifts 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 3.11 shows the minimum weekly demands for the period November to April 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 recent experience is significantly impacted by the weather.

Figure 3.17: 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 http://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2014june.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.

The economic situation has remained fairly consistent since the financial meltdown and ensuing recession. The traditional recovery period has seen modest growth due to high debt loads and low consumer confidence. For this Outlook, little has changed as growth remains fragile. Weaker emerging market growth, geo-political unrest and higher oil prices continue to act as a drag on growth.

The slow pace of growth has meant that high debt loads and levels of unemployment are being brought down at a slow pace. As well, income growth has been weak further dampening consumer confidence. To date, economic news remains mixed.

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	58.0	-22.1	1.353	1.32
2014 (f)	6,948	1.1	54.0	-6.9	1.368	1.06
2015 (f)	7,060	1.6	53.1	-1.7	1.386	1.32

In the previous report, we highlighted the shifting patterns in Ontario's employment. In particular, it was noted that Ontario employment was shifting to the service sector and into the GTA. That trend continues and is seen in the following graphs.

Figure 4.1 shows the year over year change in employment for Ontario, the Toronto zone and all other zones combined. Since the last document, the non-Toronto zones did generate some employment growth at the end of 2013 but have, since the start of 2014, been shedding them. This illustrates that the post recessionary period had fairly balanced job creation, but from May 2012 on, the vast majority of the employment growth has been in the Toronto area.

Figure 4.2 shows the year over year changes in employment broken down into services, manufacturing and other goods (mining, construction, agriculture, forestry etc.). The past half year has seen the service sector continue to grow, while manufacturing employment continues to shrink. The rise in the "Other" category is primarily attributable to growth in the construction sector. Manufacturing jobs started to disappear when the Canadian dollar started appreciating in 2003-04. Since the recession, manufacturing has stabilized but has rarely been a source of job growth.

The growth in the job market is a reflection of the on-going structural change as Ontario shifts away from energy intensive industries to a more service based economy. This is part evolution – the maturing of an economy – and part revolution – the elimination of unproductive resources during the recession. This helps explain the relative stable electricity demand against a rise in gross domestic product (GDP).

Ontario still has vast natural resources that would translate into increased electric load as they are extracted and processed. However, those developments are more relevant to a longer forecast horizon. Combined, the state of the global economy and the structural changes in the

Ontario economy mean that electricity demand growth will not be fuelled by economic growth over the Outlook period.

Figure 4.1: Zonal Employment Growth

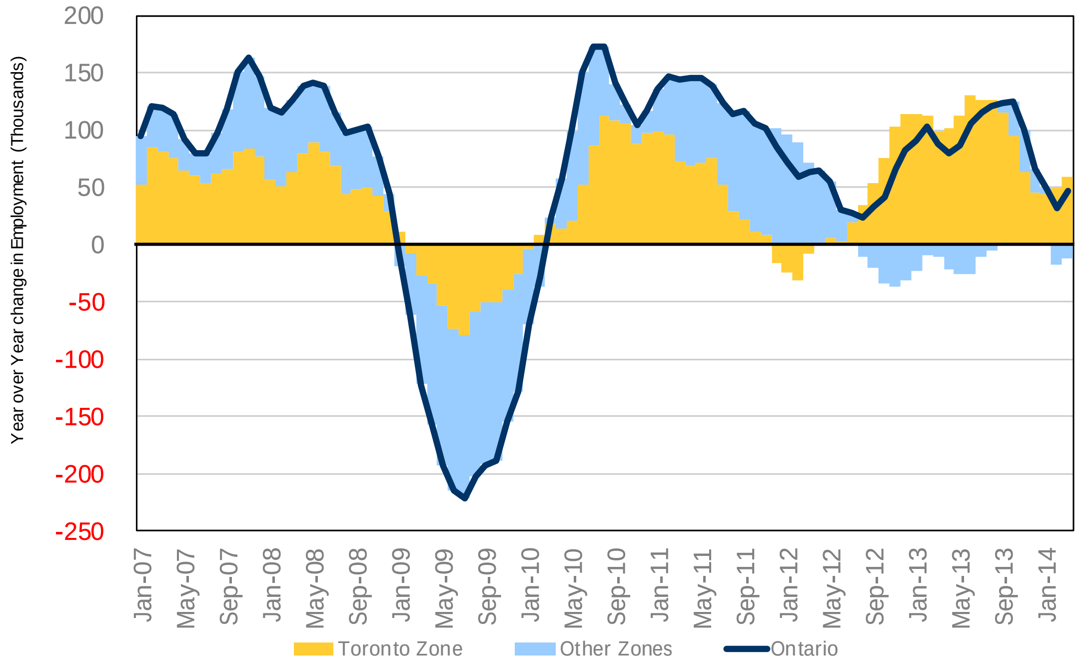
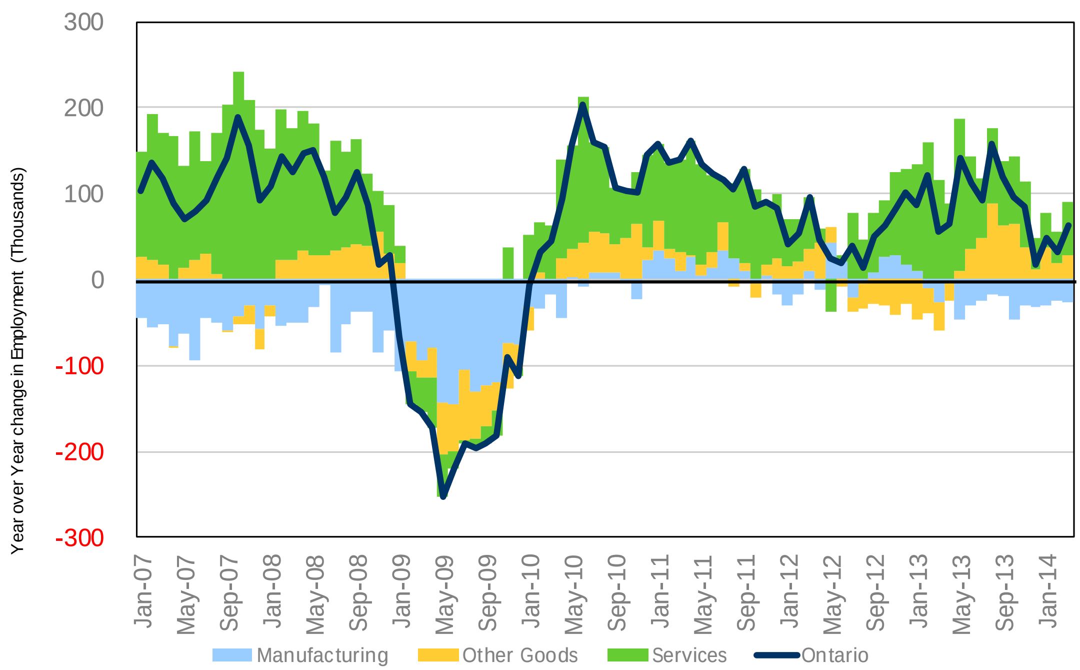


Figure 4.2: Composition of Ontario's Employment Growth



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 Conservation and Demand Measures

There are a number of initiatives and policies that have an impact on electricity demand. They can be grouped as follows; conservation, prices, embedded generation and demand measures. Each impacts demand in a different way.

Conservation

Conservation includes energy efficiency programs, conservation behaviour and fuel switching. Projected conservation numbers are provided to the IESO by the Ontario Power Authority (OPA). These projections are based on existing and future programs. Projected conservation impacts are decremented from demand.

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.

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 programs 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. The means that peaks will be impacted more than energy.

The ICI has had a significant impact on peak demand on hot summer days. Class A customers can manage their Global Adjustment costs by reducing their consumption on the five days with the highest peaks. 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. Over the summer of 2013, the GAA impacts were nearly 900 MW on the five peak days and roughly 100 MW on the next highest five peak days. The reduction for peaks 6-10 was less than previous years. This is attributable to the fact that the five highest days occurred within the same week and there was a significant drop in demand between the fifth highest peak and the sixth.

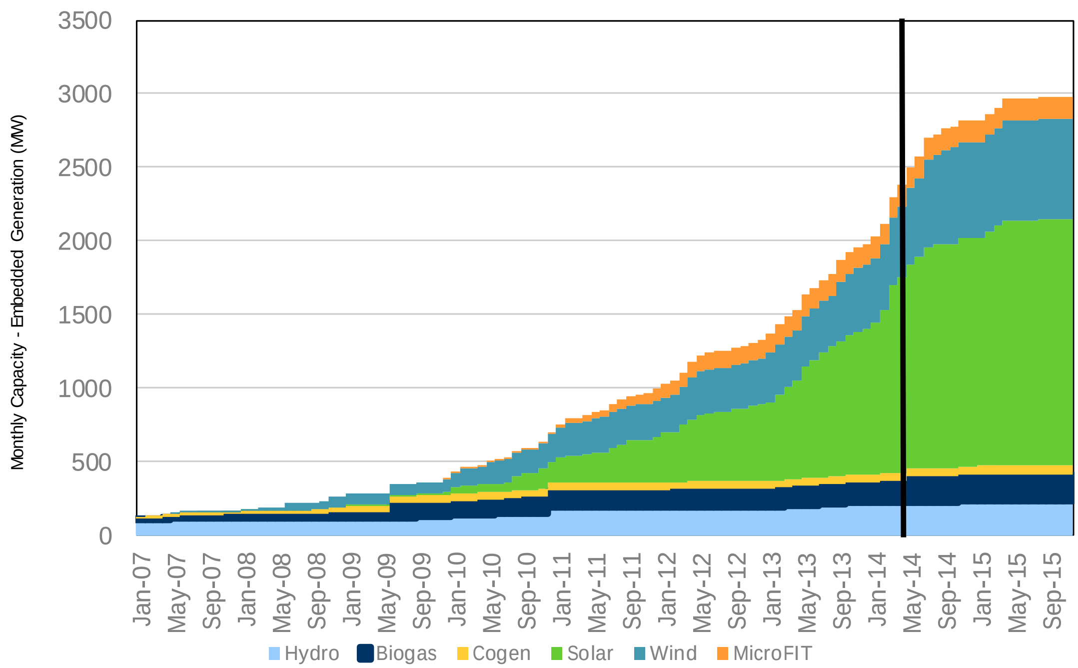
Embedded Generation

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).

Information on embedded generation is factored into the forecast and decremented from demand. Embedded generation will displace demand that would normally have been supplied through the IESO grid. Although the actual demand for electricity is unaltered, the source of supply changes and must be reflected in this forecast of grid supplied electricity. Embedded generation will impact both peak and energy demand. The mix of embedded generation will determine the seasonal impacts.

Over the course of the 18-Month forecast, 474 MW of embedded generation capacity is projected to be added to the distribution system. The majority will be solar (286 MW) and wind (169 MW). The remaining 19 MW will be a mix of bio-fuel, hydro and natural gas. By the end of the forecast period the estimated embedded capacity will be 2,925 MW of which 57% will be solar powered and 23% will be wind powered. The large solar capacity will have a significant impact on the summer peak but no impact on the winter peak – as the winter peak occurs after the sun has set. Figure 4.3 shows the projected embedded generation capacity for the Outlook period.

Figure 4.3: Projected Embedded Generation Capacity



Demand Measures

Demand measures include the OPA's demand response programs, peaksaver PLUS and the dispatchable loads program. The OPA provides the demand response capacity for its programs and the dispatchable loads capacity is derived from historical information. The demand forecast is not altered for demand measures as they are treated as resources.

- End of Document -