18-MONTH OUTLOOK

From December 2013 to May 2015

ieso

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 December 2013 to May 2015 and supersedes the previous forecast released in September 2013.

Economic Outlook

Economic growth since the 2008-09 recession has been low by historical standards. High debt loads and high unemployment rates continue to have a chilling effect on consumer confidence. With consumer spending the largest segment of the economy it is not surprising that overall growth has been weak. Government spending, after years of stimulation policies and high debts, is also being curbed as austerity measures are introduced. The last economic component would be trade. Increasing demand for goods and services from developing nations will help Ontario's economy. As well, the European Union free trade agreement will further spur Ontario exports once the agreement is finalized.

Canada still enjoys strong fundamentals compared to other countries. Low interest rates, a robust financial sector and vast mineral resources certainly help the country's long term growth prospects. Additionally, an improving global economy, and in particular a stronger U.S. economy will help stimulate the demand for Ontario goods.

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 May through October.

Overall, energy demand for the six months was down a significant 3.4% compared to the same six months a year previous. In fact, demand for the six months was down 1.8% compared to the period May 2011 to October 2011. Much of this reduction is due to the weather experienced over that time frame. After correcting for weather, electricity demand for the six months was down 1.5% compared to the year previous and down 0.2% compared to the period two years previous.

This decline is a marked difference to how 2013 started. The latter part of 2012 and the beginning of 2013 had shown strong year over year growth. However, starting in late spring demand started to show weakness.

On the positive side, wholesale customers continue to show growth over the same time frame a year earlier. Growth for the May to October period is up 1.0% compared to a year ago and up 5.9% over the same period two years prior. Since January 2012, wholesale customer's consumption has shown year over year growth in 17 in the 21 months. The growth has been modest but fairly consistent. In October, average hourly demand from wholesale customers topped 2,000 MW for only the second time since the recession.

The 2013 summer peak of 24,927 MW occurred on July 17th, which was not the hottest the day of the summer but was very close both in terms of the date and the weather conditions. Despite the high peak, no demand measures were activated at the time.

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 effects of demand measures are added back into the demand history and the forecast is generated based on these adjusted demand numbers. The estimated impacts stemming from the Global Adjustment Allocation 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. Winter peak demands will show a slight decrease over the forecast horizon as a result of downward pressure from gains in lighting efficiency. Summer peaks will face greater downward pressure from numerous sources - air conditioning efficiency, global adjustment impacts and solar embedded generation.

Energy demand is expected to show a small decrease in 2013 due primarily to the leap year impact and the growth in embedded generation capacity. Demand is expected to remain flat in 2014 as the growth in embedded generation and conservation savings offset demand growth due to economic expansion and population growth.

Table 1: Peak and Energy Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2013-14	22,320	23,304
Summer 2014	22,917	24,848
Winter 2014-15	22,294	23,230
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 (Forecast)	140.6	-0.5%
2014 Energy (Forecast)	140.7	0.1%

- End of Section

Caution and Disclaimer

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. The demand forecast is generated quarterly and a separate Ontario Demand Forecast document is released twice per year. This Ontario Demand Forecast supports this requirement and covers the period from December 2013 to May 2015. It supersedes the previous forecast released in September 2013 and the previous Ontario Demand Forecast document released in May 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/imoweb/pubs/marketReports/Methodology_RTAA_2013dec.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 is based on actual demand, weather and economic data through the end of August. Data for September and October 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/imoweb/pubs/marketReports/18MonthOutlookTables_2013dec.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.

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-Dec-13	20,721	22,231	677	2,899	07-Sep-14	18,994	22,374	1,370	2,453
15-Dec-13	21,284	22,324	496	2,940	14-Sep-14	18,775	21,021	680	2,453
22-Dec-13	21,395	22,502	585	2,966	21-Sep-14	18,619	19,736	781	2,515
29-Dec-13	19,358	20,827	755	2,725	28-Sep-14	17,746	17,997	420	2,463
05-Jan-14	20,820	21,445	353	2,848	05-Oct-14	16,982	17,441	554	2,464
12-Jan-14	22,320	23,304	570	3,050	12-Oct-14	17,241	17,732	786	2,501
19-Jan-14	21,781	22,656	547	2,995	19-Oct-14	17,962	18,348	507	2,486
26-Jan-14	21,906	22,656	483	3,007	26-Oct-14	17,945	18,365	392	2,553
02-Feb-14	21,759	22,585	404	3,042	02-Nov-14	18,533	18,926	318	2,608
09-Feb-14	20,964	22,250	734	2,991	09-Nov-14	18,830	19,569	416	2,651
16-Feb-14	20,552	22,053	635	2,906	16-Nov-14	19,398	20,047	601	2,716
23-Feb-14	20,324	21,916	581	2,871	23-Nov-14	19,877	20,629	342	2,767
02-Mar-14	20,886	21,842	501	2,943	30-Nov-14	20,391	21,535	607	2,818
09-Mar-14	19,976	21,334	531	2,859	07-Dec-14	20,918	21,989	409	2,887
16-Mar-14	18,961	20,500	649	2,767	14-Dec-14	20,734	21,969	555	2,888
23-Mar-14	18,365	19,681	611	2,661	21-Dec-14	21,027	22,233	690	2,927
30-Mar-14	18,444	20,202	569	2,689	28-Dec-14	20,163	21,160	362	2,750
06-Apr-14	17,732	19,655	567	2,622	04-Jan-15	20,358	21,385	528	2,823
13-Apr-14	17,463	19,033	471	2,542	11-Jan-15	22,294	23,230	570	3,024
20-Apr-14	17,005	17,777	496	2,450	18-Jan-15	21,639	22,482	547	2,973
27-Apr-14	16,899	17,653	531	2,448	25-Jan-15	21,735	22,424	483	2,976
04-May-14	17,587	19,512	721	2,457	01-Feb-15	21,747	22,426	404	3,011
11-May-14	17,685	19,884	849	2,438	08-Feb-15	21,027	22,079	734	2,966
18-May-14	18,558	21,905	845	2,466	15-Feb-15	20,489	21,867	635	2,884
25-May-14	18,955	22,025	1,175	2,418	22-Feb-15	20,164	21,768	581	2,839
01-Jun-14	19,049	22,258	1,330	2,502	01-Mar-15	20,749	21,755	501	2,919
08-Jun-14	19,969	23,387	1,292	2,639	08-Mar-15	19,880	20,638	531	2,835
15-Jun-14	20,915	23,799	1,055	2,683	15-Mar-15	18,855	19,782	649	2,751
22-Jun-14	21,768	24,051	835	2,767	22-Mar-15	18,274	18,963	611	2,648
29-Jun-14	22,521	24,318	754	2,770	29-Mar-15	18,314	19,448	569	2,653
06-Jul-14	22,557	23,969	1,016	2,676	05-Apr-15	18,037	18,732	567	2,567
13-Jul-14	22,917	24,848	814	2,754	12-Apr-15	17,547	18,480	471	2,526
20-Jul-14	22,780	23,800	838	2,703	19-Apr-15	16,782	17,154	496	2,485
27-Jul-14	22,134	24,021	1,035	2,786	26-Apr-15	16,661	17,057	531	2,460
03-Aug-14	22,115	24,272	841	2,786	03-May-15	17,487	19,816	721	2,440
10-Aug-14	21,373	24,464	958	2,684	10-May-15	17,541	20,139	849	2,418
17-Aug-14	21,279	23,847	985	2,695	17-May-15	18,419	21,666	845	2,443
24-Aug-14	21,256	23,511	1,362	2,733	24-May-15	18,813	21,770	1,175	2,394
31-Aug-14	20,153	22,866	1,413	2,638	31-May-15	19,327	21,528	1,330	2,446

Compared to the previous forecast the overall energy demand is lower though it varies by month. Likewise, the weekly peaks were generally lower though they too vary by month. 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

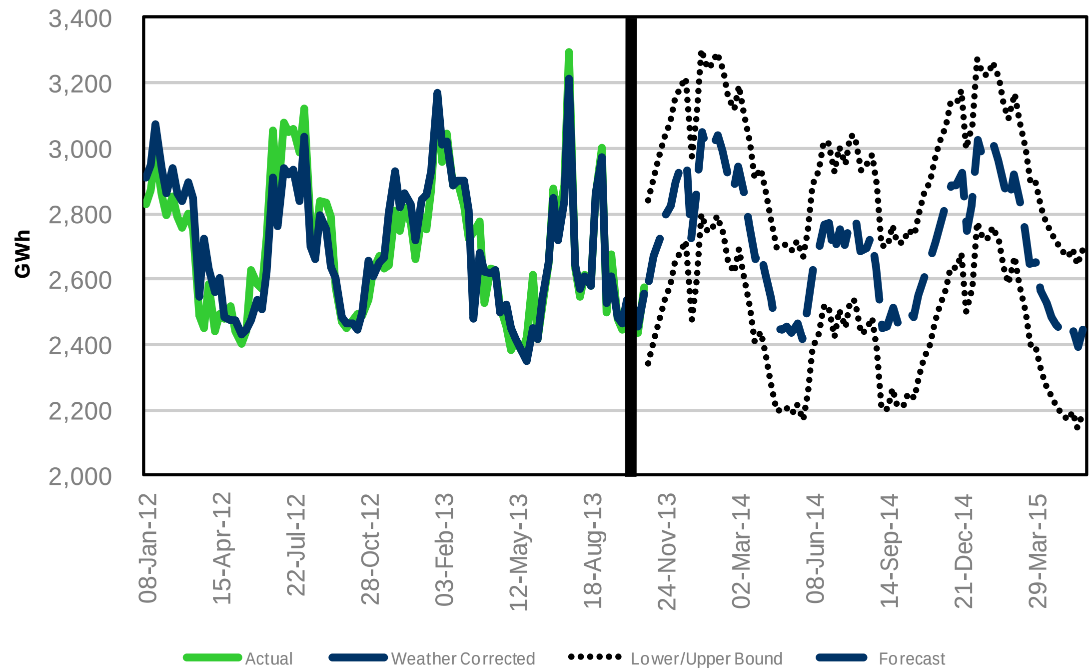
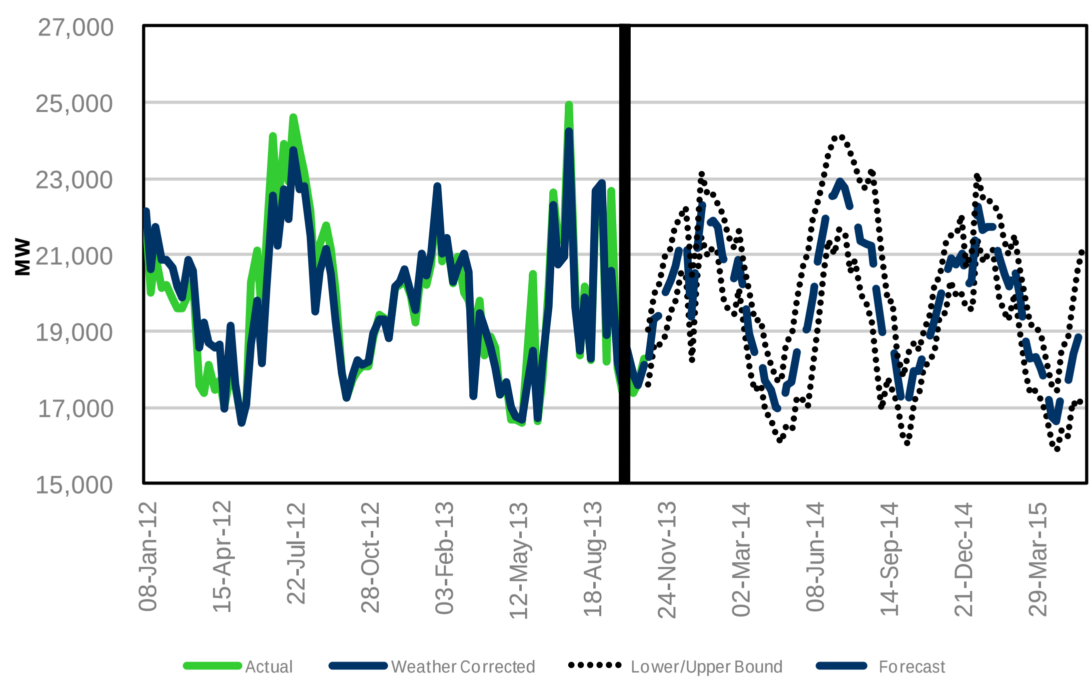


Figure 2.2: Weekly Peak Demand – History and Forecast



- 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 – May to October

Since the last Ontario Demand document actuals have been recorded for the period May to October. The summer of 2013 was close to normal. Table 3.1 contains a summary of the weather and demand for the past six months.

<u>May</u>

- May was warmer than normal and the peak occurred on May 31st which was the hottest day of the month.
- The 20,488 MW peak was driven by the hot temperatures on that day. The weather corrected peak was a much more modest 18,498 MW. Both the actual and weather corrected peak are lower than the previous May.
- Energy demand for the month was 10.8 TWh (10.7 TWh weather corrected). This represents a reduction from the previous May. It also represents the start of several months of year over year decline. Prior to May, energy demand had increased in 11 of the previous 12 months.
- Minimum demand (10,765 MW) was the lowest May value since market opening.
- Wholesale industrial consumption was 1.1% lower than May 2012. Much of the decline comes from pulp and paper and iron and steel industries.

<u>June</u>

- June's weather was cooler than normal. Though the average temperature was milder than normal, the peak temperature was close to normal. The peak occurred on the hottest day of the month.
- The 22,662 MW peak and the weather corrected peak of 22,324 MW were both lower than the previous June. The numbers were comparable to those following the recession.
- Energy demand for the month was 11.2 TWh (both actual and weather corrected) and are the lowest observations for June since the recession.
- Minimum demand (10,816 MW) was lower than June 2012, though higher than June 2011.
- Wholesale industrial customers' consumption increased, rising 2.1% over the previous June. Much of the growth came from the mining sector.

<u>July</u>

- The weather for July was warmer than normal. The peak did not occur on the hottest day, but was very close to it (in terms of temperature and date).
- The July peak was 24,927 MW and 24,256 MW weather corrected. Both are an increase over July 2012. The weather corrected peak was the highest July peak post-recession.

- Energy demand for the month was 12.7 TWh and 12.6 TWh weather corrected. Both are the lowest July totals since the recession.
- Minimum demand was 11,506 MW and is in line with the July minimums since the recession.
- Wholesale industrial consumption was 2.7% lower than the previous July. Most of the reduction was due to changes in iron and steel production. Despite the decline, the mining sector continued to show strong growth.

August

- The weather for August was cooler than normal. The peak did not occur on the hottest day of the month but the fourth highest. Since the peak temperatures were fairly mild, there was little differentiation across the warmest days.
- The actual peak (22,833 MW) was lower than the previous August while the weather corrected peak (22,892 MW) showed a slight increase. They both are on the low side based on historical peaks.
- Energy demand was 12.1 TWh (both actual and weather corrected) which was lower than the previous August and the lowest August value since market opening.
- Minimum demand for the month was 11,139 MW which is the lowest August value since market opening with the exception of the August 2009 recession figure.
- The 4.2% drop in overall energy demand was not fuelled by the Wholesale customers' consumption as that fell only by a modest 0.7%. For the month the petroleum and iron and steel industries showed year over year declines whereas the mining sector continued to show year over year increased consumption.

September

- The weather for September was pretty close to normal though the peak temperature was higher than normal.
- The month's peak demand of 22,682 MW (20,604 MW weather corrected) was an increase over the previous September. However, the peak was significantly lower than the 24,444 MW recorded in September 2010. Part of the explanation would be that this year's peak occurred later in the month once air conditioning loads had diminished.
- Energy demand was 10.8 TWh (both actual and weather weather-corrected), a decline from 2012.
- The minimum demand of 11,003 MW is typical of the post-recession period.
- After two months of year-over-year declines, wholesale customers' consumption grew by a very strong 4.0% over September 2012. The growth came from the mining and rubber products sectors.

October

- The weather for October was pretty close to normal. The peak occurred on the second coldest day of the month.
- The peak for the month was 18,445 MW (18,888 MW weather corrected) which is fairly consistent for October values since 2009.

- The energy for the month was 11.1 TWh (11.3 TWh weather corrected). These numbers are also consistent with October demands since 2009.
- The minimum demand of 11,018 MW is the lowest for October since 2010.
- Wholesale customers' consumption growth was quite strong for the second consecutive month reaching a 4.4% increase over the previous October. Once again the growth was led by the mining sector with chemicals also showing strong growth.

Overall, energy demand for the six months was down 3.4% compared with the same six months a year prior. Much of that decline was due to the mild 2013 summer, so after correcting for weather the reduction is a smaller 1.8%. Over the same time, wholesale consumers' consumption had shown an increase of 1.0%.

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

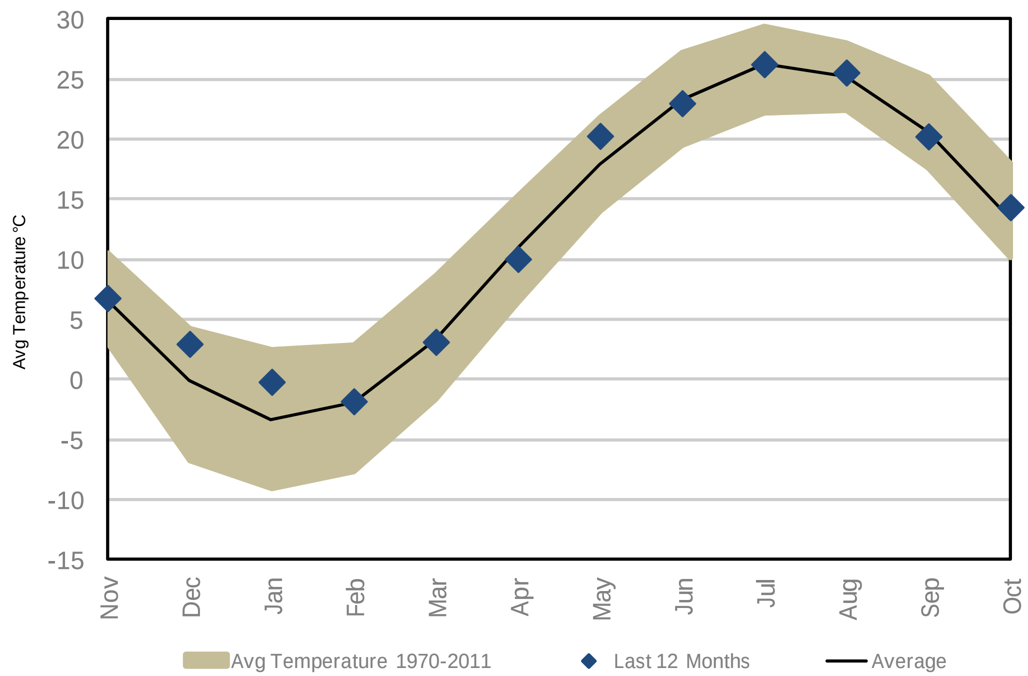
Table 3.1 contains a summary of the weather and demand for the past six months. Figure 3.1 shows the average daily high temperature by month for past 12 months compared to the history for 1970-2011.

Table 3.1: Historical 2012 Weather and Demand Summary

Historical Analysis		May	June	July	August	September	October
Actual	Average Temperature (°C)	20.3	23.0	26.2	25.5	20.2	14.3
	Minimum Temperature (°C)	7.1	14.8	21.2	20.0	11.5	0.0
	Maximum Temperature (°C)	30.3	31.9	34.3	31.4	33.9	24.6
Monthly Normal	Normal Average Temperature (°C)	17.1	23.8	26.4	24.4	20.9	12.6
	Normal Minimum Temperature (°C)	8.7	13.4	20.0	18.2	9.5	4.0
	Normal Maximum Temperature (°C)	27.2	31.3	30.9	30.8	29.8	21.1
Actual	Peak Demand (MW)	20,488	22,662	24,927	22,833	22,682	18,445
	Average Hour (MW)	14,497	15,520	17,100	16,264	15,052	14,967
	Minimum Hour (MW)	10,765	10,816	11,506	11,139	11,003	11,018
	90th Percentile (MW)	16,611	18,354	21,288	20,243	17,400	17,040
	Percent above 20,000 (MW)	0.6%	6.0%	16.5%	11.4%	2.9%	0.0%
	# of Hours Above 20,000 (MW)	4	43	123	85	21	0
	Energy Demand (GWh)	10,785	11,175	12,723	12,100	10,837	11,136
Weather Corrected	Peak Demand (MW)	18,498	22,324	24,256	22,892	20,604	18,888
	Energy Demand (GWh)	10,658	11,176	12,554	12,090	10,800	11,280
Forecast	Peak Demand (MW)	19,101	22,499	23,213	22,360	20,513	18,388
	Energy Demand (GWh)	10,932	11,406	12,480	12,228	11,015	11,279

Notes for Table 3.1 – Weather is for Toronto. Temperature is the daily high. Forecast is the most recent for that period.

Figure 3.1: Average Daily High Temperatures (Toronto)



3.2 Historical Energy Demand

Overall energy demand has fallen compared to the same six months a year previous. This decline can be attributed to a number of factors. Conservation programs and the growth in embedded generation have led to a reduction in the demand for grid-supplied electricity.

Energy demand for 2013 is projected to decline by 0.5% compared to 2012. After adjusting for the impact of the leap year, demand will remain almost flat. The year started out showing year over year growth but deteriorated over the course of the year. Whereas distributor's consumption has declined year over year for seven of the ten months this year, wholesale industrial customers' consumption has increased in seven of the ten months. Part of the discrepancy can be attributed to weather impacts as industrial load is not as weather sensitive as distributor loads. Also, wholesale loads are not impacted by embedded generation whereas distributor loads are. Likewise, conservation initiatives and time of use rates have had a significant impact on distributor loads, though these factors and the Global Adjustment Allocation also impact industrial loads as well.

Figure 3.2 shows the year-over-year change in wholesale customers' average hourly consumption. The graph shows the downward trend beginning in the spring of 2005. With the rise of the Canadian dollar, export oriented energy intensive industries began to see declines in their output. Over the same period, the pulp and paper sector, which historically was the largest consumer of electricity, began to experience declines due to fundamental changes in the industry. With more recycled content and less demand for newsprint, the sector saw significant reductions. The impact of the recession can clearly be seen in the chart. As well, the recovery period shows periods of both growth and loss.

Figure 3.2: Wholesale Customers' Year-over-Year Change in Consumption

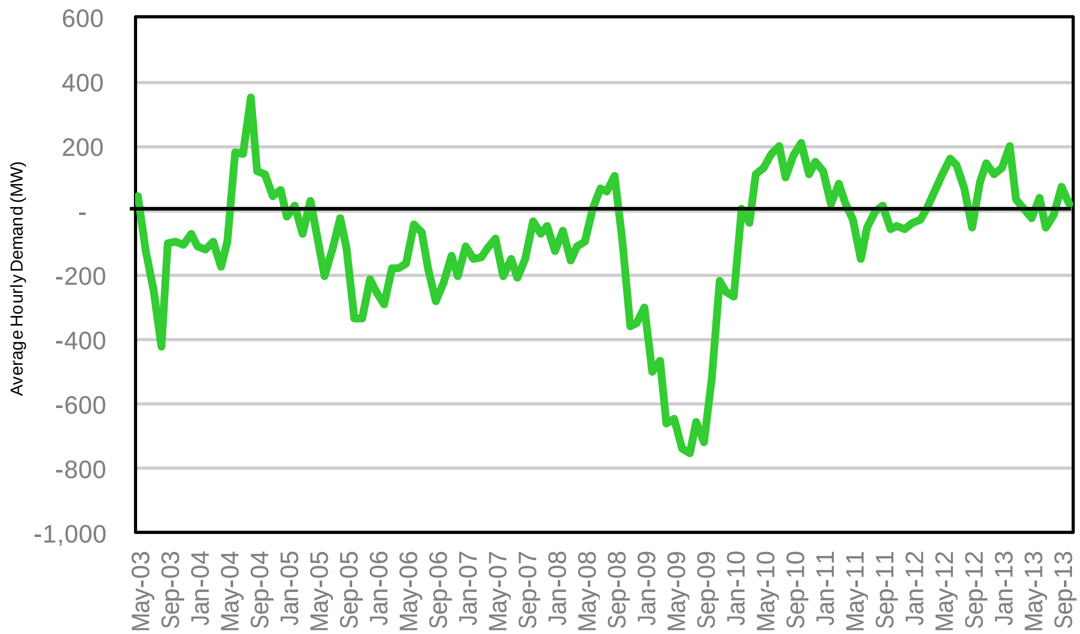


Figure 3.3: Wholesale Customers' Average Hourly Consumption by Industry Segment

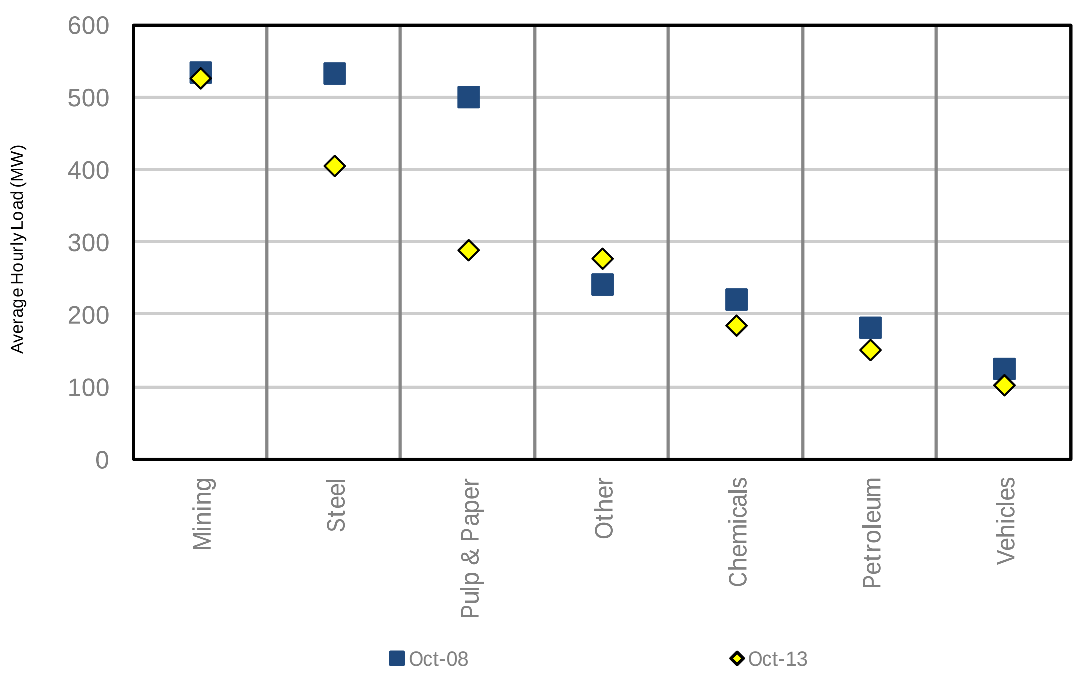


Figure 3.3 shows the wholesale customers' average hourly load by industry segment for the ten months of 2013 compared to the same ten months prior to the recession. The graph highlights two main issues. First, most of the sectors – with the exception of Other which are the remaining sectors – are lower than prior to the recession. Second, the greatest losses are focused in what were previously some of the biggest consumers (Steel and Pulp & Paper).

Energy demand has remained fairly flat following the recession. Though some of this is due to the impact of the economy on overall electricity consumption, much of the reduced demand growth is due to the rise of conservation and embedded generation capacity over the past three years.

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. Throughout the forecast, the embedded generation component will continue to grow as renewable energy contracts come into commercial operation.

Figure 3.4: Monthly Energy Demand and Embedded Generation

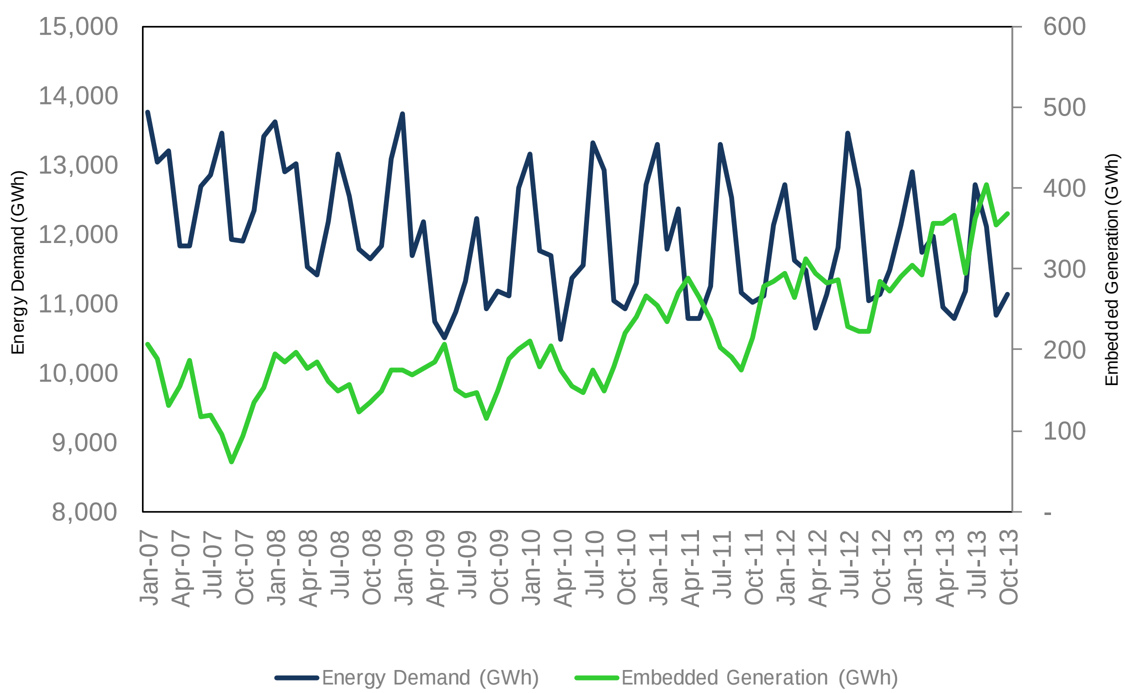


Table 3.2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week and notes any item of significance for the week. If the weather-corrected demand is greater than the actual demand, it means that the actual weather was milder than 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
18	05-May-13	29-Apr-13	2,382	2,449	
19	12-May-13	08-May-13	2,411	2,415	
20	19-May-13	13-May-13	2,377	2,379	
21	26-May-13	21-May-13	2,423	2,349	Victoria Day
22	02-Jun-13	31-May-13	2,616	2,449	
23	09-Jun-13	06-Jun-13	2,418	2,419	
24	16-Jun-13	12-Jun-13	2,520	2,540	
25	23-Jun-13	23-Jun-13	2,649	2,654	
26	30-Jun-13	24-Jun-13	2,876	2,851	
27	07-Jul-13	04-Jul-13	2,779	2,720	Canada Day
28	14-Jul-13	10-Jul-13	2,887	2,837	
29	21-Jul-13	17-Jul-13	3,296	3,212	
30	28-Jul-13	23-Jul-13	2,632	2,641	
31	04-Aug-13	01-Aug-13	2,547	2,569	
32	11-Aug-13	08-Aug-13	2,615	2,609	Civic Holiday
33	18-Aug-13	12-Aug-13	2,581	2,582	
34	25-Aug-13	21-Aug-13	2,857	2,862	
35	01-Sep-13	29-Aug-13	3,000	2,975	
36	08-Sep-13	04-Sep-13	2,498	2,526	Labour Day
37	15-Sep-13	10-Sep-13	2,675	2,611	
38	22-Sep-13	20-Sep-13	2,478	2,486	
39	29-Sep-13	26-Sep-13	2,444	2,466	
40	06-Oct-13	02-Oct-13	2,530	2,535	
41	13-Oct-13	08-Oct-13	2,442	2,518	
42	20-Oct-13	15-Oct-13	2,434	2,453	Thanksgiving Day
43	27-Oct-13	24-Oct-13	2,576	2,555	

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 Global Adjustment allocation (GAA) and lower levels of economic activity have all contributed to lower peak demands.

The 2013 summer peak was 24,927 MW which was higher than last summer's peak (24,636 MW). Unlike last summer's peak there was no demand response activity at the time of the peak. This is markedly different from the summer of 2012 where there were 385 MW of demand measures during the peak.

Summer peaks have been facing significant downward pressure. Conservation initiatives aimed at improving air conditioner efficiency have a direct impact on summer peaks. With the vast majority of embedded generation being solar powered, the summer peak will be dramatically affected. Unlike the winter peak which occurs after sunset, the summer peak occurs during the hours of prime solar production. Demand response capacity is also greater during the summer peak period thanks to the Peaksaver program. Additionally, the GAA peaks have all occurred in the summer leading to further reductions in the summer peak values observed.

Figure 3.5 illustrates the impact that the GAA is having on directly connected industrials. The graph shows the average hourly and peak hour load by month. Note that with the introduction of the GAA in 2010, there has been a separation in the average and peak hour loads during the summer months. This shows that Class A customers are responding in order to minimize their Global Adjustment costs with the impacts roughly 600 MW.

Figure 3.5: Wholesale Customers' Coincident Peak and Average Hourly Consumption

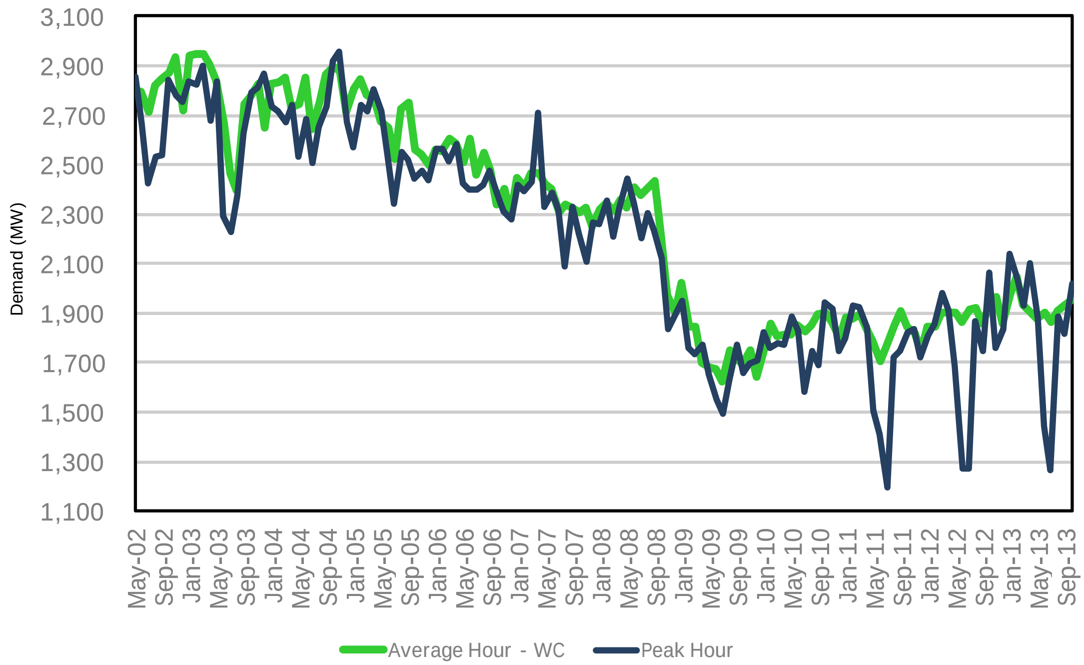


Table 3.3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3.3: Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
18	05-May-13	29-Apr-13	16,697	17,002	13.1
19	12-May-13	08-May-13	16,694	16,766	21.8
20	19-May-13	13-May-13	16,609	16,670	10.8
21	26-May-13	21-May-13	18,234	17,490	24.6
22	02-Jun-13	31-May-13	20,488	18,498	29.9
23	09-Jun-13	06-Jun-13	16,632	16,724	14.8
24	16-Jun-13	12-Jun-13	17,728	18,157	22.4
25	23-Jun-13	23-Jun-13	20,208	19,644	31.9
26	30-Jun-13	24-Jun-13	22,662	22,324	31.6
27	07-Jul-13	04-Jul-13	21,386	20,745	27.8
28	14-Jul-13	10-Jul-13	21,756	20,976	30.5
29	21-Jul-13	17-Jul-13	24,927	24,256	34.3
30	28-Jul-13	23-Jul-13	20,185	19,642	27.4
31	04-Aug-13	01-Aug-13	18,363	18,479	25.7
32	11-Aug-13	08-Aug-13	20,161	19,910	26.5
33	18-Aug-13	12-Aug-13	18,265	18,305	23.0
34	25-Aug-13	21-Aug-13	22,179	22,674	31.4
35	01-Sep-13	29-Aug-13	22,833	22,892	28.2
36	08-Sep-13	04-Sep-13	18,225	18,893	25.3
37	15-Sep-13	10-Sep-13	22,682	20,604	33.9
38	22-Sep-13	20-Sep-13	18,024	18,200	23.5
39	29-Sep-13	26-Sep-13	17,411	17,647	20.5
40	06-Oct-13	02-Oct-13	18,009	18,528	24.6
41	13-Oct-13	08-Oct-13	17,402	17,870	16.5
42	20-Oct-13	15-Oct-13	17,627	17,571	17.1
43	27-Oct-13	24-Oct-13	18,299	18,132	8.3

3.4 Load Duration Curves

The following load duration curves display load for the four seasons. The seasons are defined as, summer (June, July and August), spring (March, April and May), winter (December, January and February) and fall (September, October and November). The following graphs are presented in reverse order with the most recent data (summer) first (Figures 3.6 to 3.9).

The figures are not weather-corrected so the weather will influence the shape of each of the graphs. The impact of the milder normal summer is seen in the load duration curve. Likewise, the extremely mild winter weather is very evident in the winter load duration curve.

The spring and fall load duration curves are more heavily influenced by the level of economic activity than by the weather. All the load duration curves show that demand remains low by historical standards.

Figure 3.6: Summer Load Duration Curve

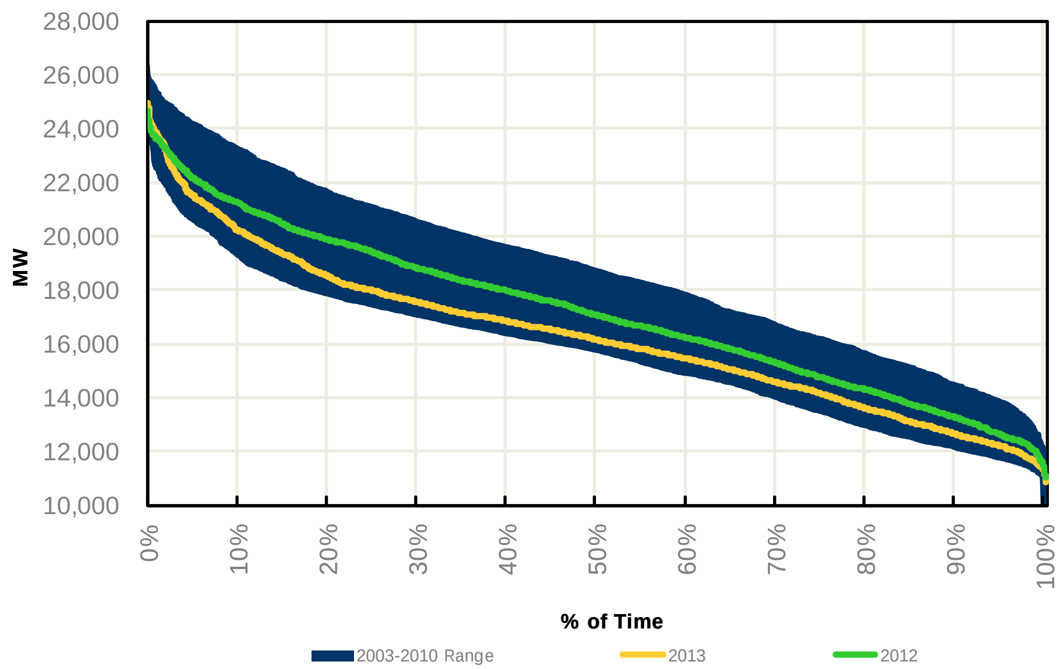


Figure 3.7: Spring Load Duration Curve

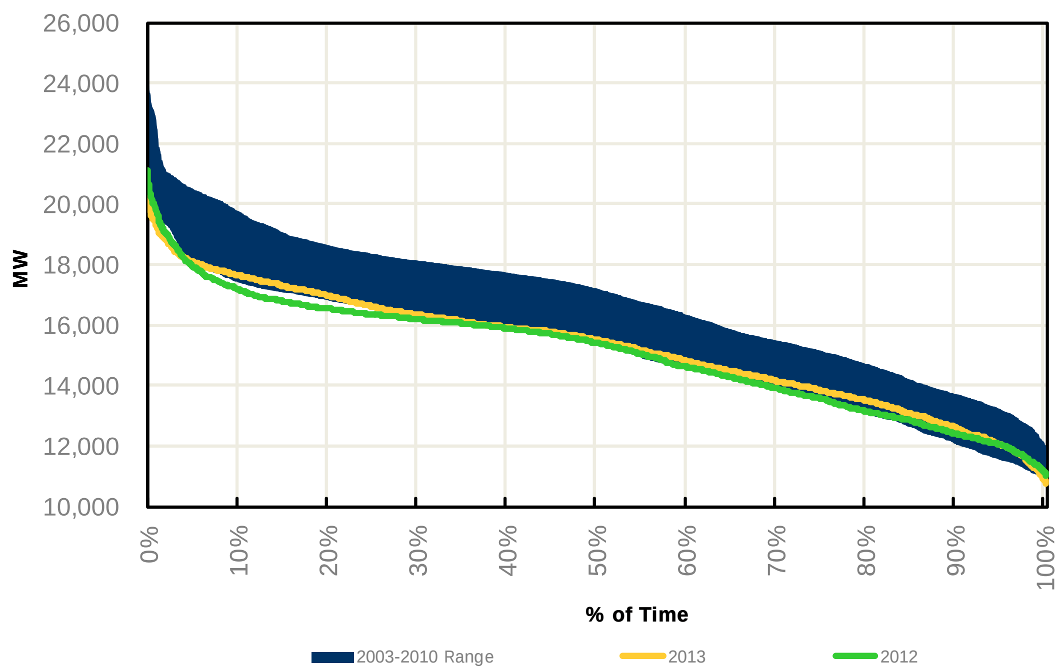


Figure 3.8: Winter Load Duration Curve

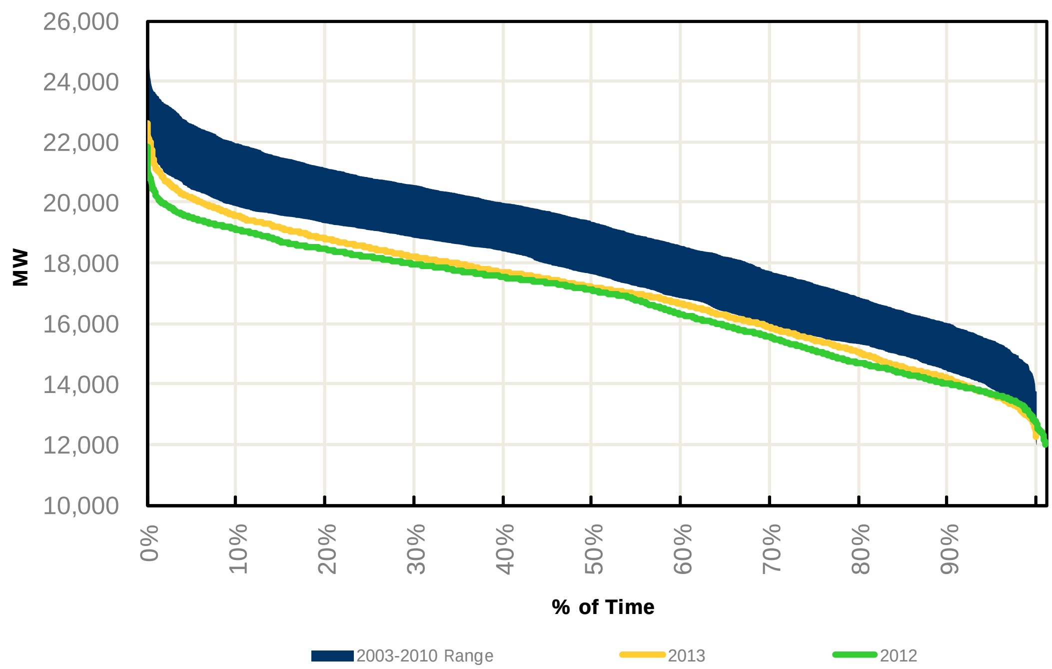
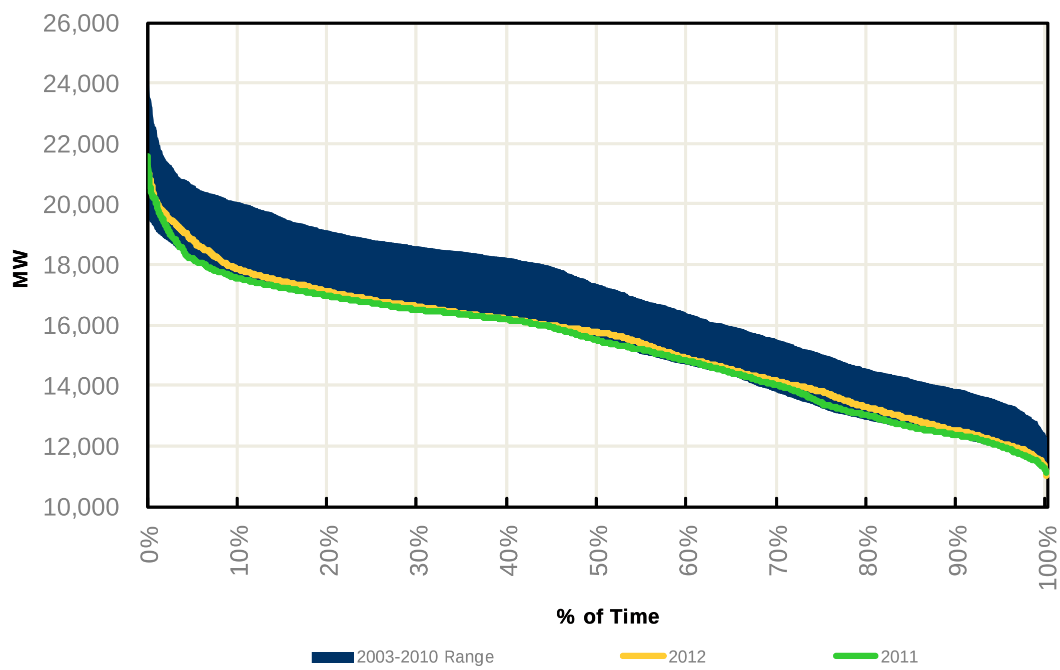


Figure 3.9: Fall Load Duration Curve



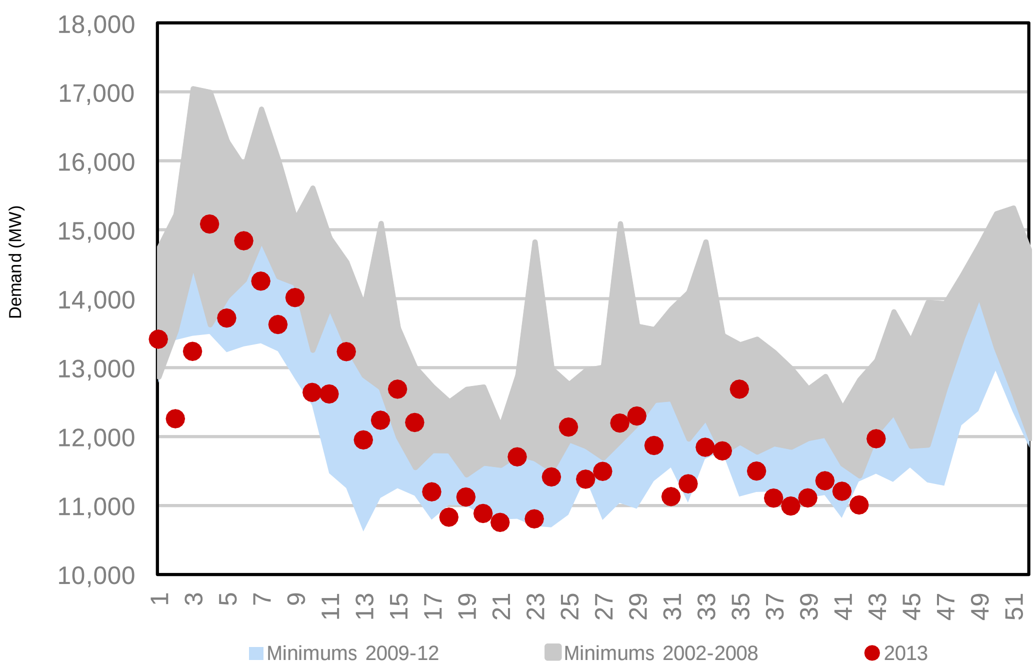
3.5 Historical Minimum Demand

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 milder weather over the course of the last six months, minimums have not seen much weather driven load. Recent minimums would have been influenced more by the level of economic activity than weather. 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 2013 against two time frames. The first time frame is the period from market opening to the end of 2008. This represents a period of relatively strong economic activity. The second period is that from the recession through to the end of 2012. With the 2008-09 recession there was a structural shift downwards in the minimum demands as energy intensive industrial loads were reduced or shifted. The observations for 2013 are more consistent with recent experience but show a slight increase consistent with the rise in wholesale customers' consumption. Since then minimum loads have shown a small increase.

Figure 3.10: 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/imoweb/pubs/marketReports/Methodology_RTAA_2013dec.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 purchased forecasts of economic data in order to generate economic drivers for the demand forecast and to provide additional insight and analysis.

The economic climate since the recession has been one of very mild expansion. Unlike most recovery periods which see rapid expansion, the post-recession period has been marked by very modest growth. Much of this has to do with the underlying economic issues. High levels of debt and unemployment have meant that consumer spending has been muted. At the same time, despite good business profits, companies have been sitting on cash. There has been much talk of trying to get this "dead money" back into the economy but businesses are reluctant to invest when the growth prospects remain relatively low.

High debt rates have also impacted governments as, after years of stimulus, they have turned to austerity measures and are reluctant to spend further. This leaves only trade as the main engine of growth. With more robust growth in the developing nations and a new European Union free trade deal on the way, this indeed may be the spark for the domestic economy.

However, over the near term it looks like more of the same – small incremental growth. Much of the growth is still coming from the service sector, but manufacturing activity has improved recently and should continue to improve over the forecast.

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.

Ontario's economy has been growing. However, that growth has not been broad based or robust. As alluded to earlier, much of the growth has been in the service sector and concentrated in the Greater Toronto Area (GTA). Figure 4.1 shows how most of the employment growth over the past year has been in the GTA. This is odd, considering the initial recovery phase in 2010-11 was spread across the province. Figure 4.2 shows the dominance of the service sector in job creation since 2010 but also that other sectors have, at times, continued to shed jobs.

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	6,686	1.5	71.9	14.6	1.294	1.50
2009	6,535	-2.3	47.9	-33.3	1.286	-0.63
2010	6,632	1.5	57.1	19.1	1.303	1.34
2011	6,724	1.4	65.2	14.3	1.321	1.37
2012	6,776	0.8	74.4	14.1	1.336	1.14
2013 (f)	6,864	1.3	57.5	-22.7	1.352	1.23
2014 (f)	6,955	1.3	54.4	-5.5	1.368	1.20
2015 (f)	7,066	1.6	50.3	-7.6	1.386	1.29

Figure 4.1: Zonal Employment Growth

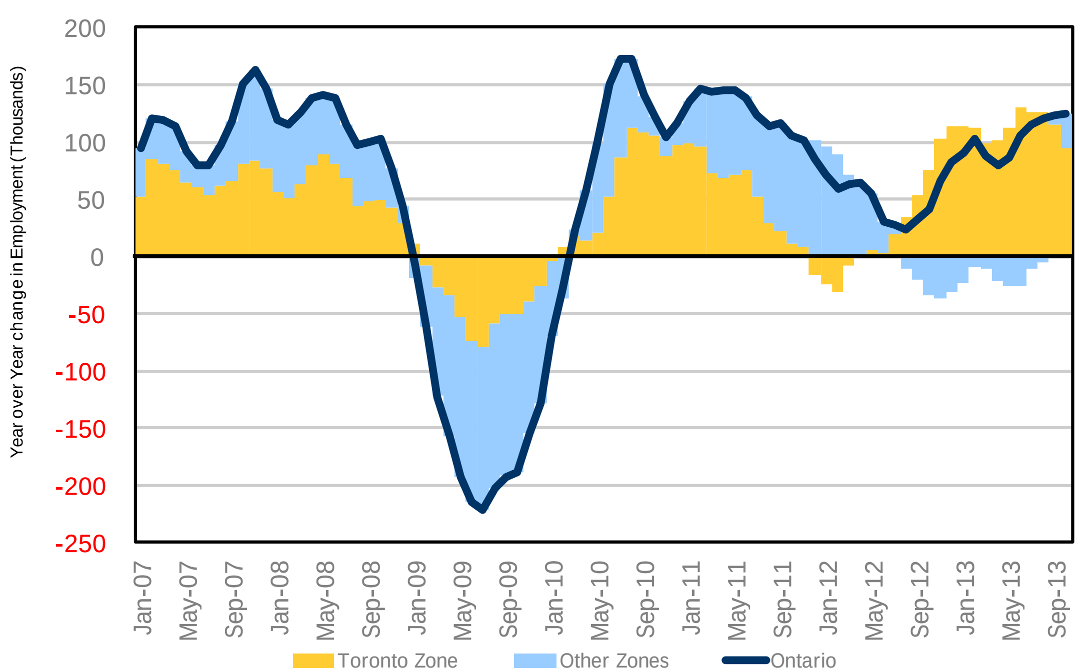
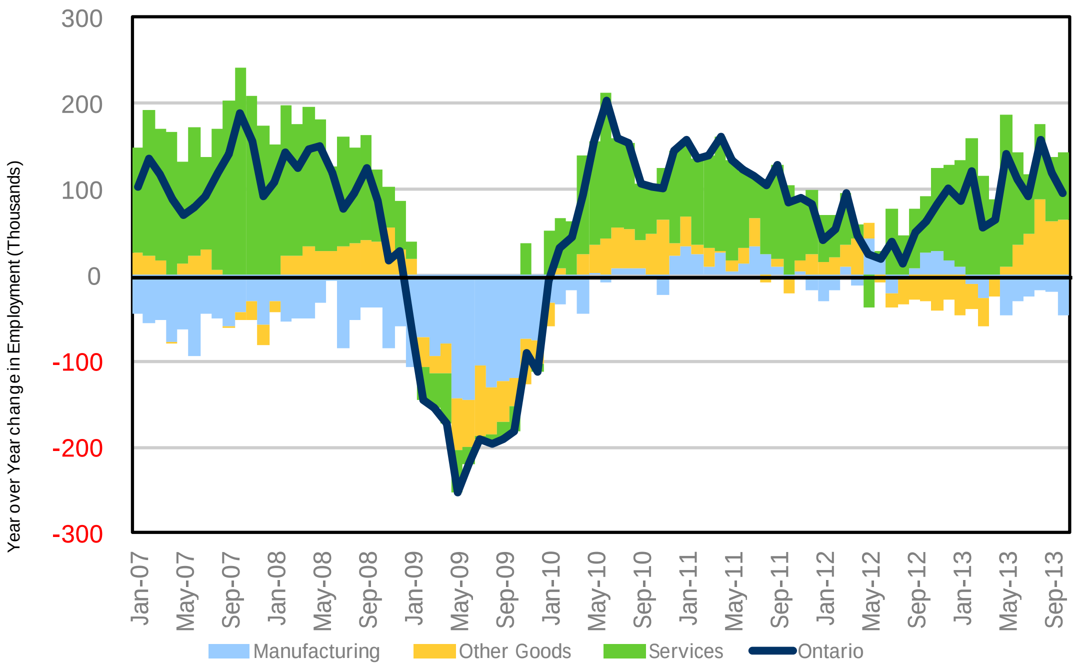


Figure 4.2: Composition of Ontario's Employment Growth



Other Goods includes mining, construction, utilities and agriculture. All of these sectors have shown both increases and declines since the recession but mining and construction have been particularly strong as of late. Some of the changes to the Ontario economy are a result of the recession and represent a one-time shift, while others represent long term structural changes. Ontario has vast natural resources which will translate into resource development and processing over the long term. Yet, at the same time, there is a natural evolution to a more service based economy due to the aging population and a maturing of the economy.

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 2010.

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. Those programs will also have varying effects by zone. Other programs, such as those 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 Global Adjustment Allocation. 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. At the same time, overall increases will help drive conservation savings through quicker payback on investments.

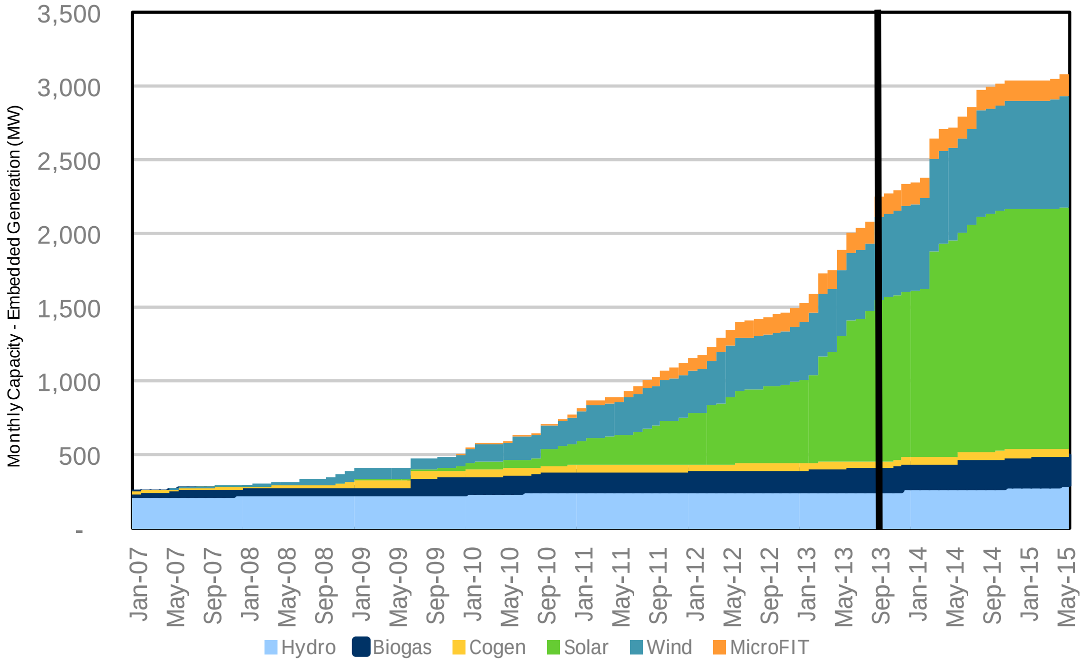
The Global Adjustment Allocation (GAA) has had a significant impact on peak demand on hot summer days. Class A customers can manage their Global Adjustment costs by reducing their consumption on the five days with the highest peaks. The impact of the GAA stretches beyond the five peak days as Class A customers will be "guessing' which days fall within those five days. Since 2013 is still on-going, the final data has not been submitted and the results therefore cannot be analyzed. The directly connected customer do not account for all Class A customers. However by looking at Figure 3.5, found earlier in this report, we can see the impact for July 2013 peak was easily over 600 MW.

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 a large volume of embedded generation capacity is projected to be added to the distribution system. The majority of this embedded generation will be solar powered. There is just over 1,200 MW of incremental embedded generation projected to be added over the forecast horizon. It is comprised of solar (800 MW), wind (400 MW), biogas (35 MW), cogeneration (5 MW) and hydro (20 MW). The large increase in 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 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.

The demand measures capacity reaches just under 1,400 MW for the period covered by this report. However, the amount of reliable or effective capacity ranges from a high of 921 MW to a low of 385 MW. The variance is due to seasonal factors (Peaksaver is only available from May to September) and offers by dispatchable loads.

- End of Document -