# Ontario Demand Forecast

JUNE 22, 2017

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# Executive Summary

The IESO is responsible for forecasting electricity demand in Ontario and for assessing whether transmission and generation facilities are adequate to meet Ontario's needs. This document presents the electricity demand forecast for the period from July 2017 to December 2018 and supersedes the previous forecast released in March 2017.

**Economic Outlook**

Currently, most experts look for Ontario to be at, or near the top, in terms of provincial growth. The expectations are that Ontario will lead in both Gross Domestic Product (GDP) and employment. Ontario had been near, or at the top in growth, the past two years and that has not translated into increased growth for electricity. Both British Columbia and Ontario have led the nation in growth, primarily a result of their strong housing markets, though this has had little impact on electricity demand – more homes will create demand as the housing stock grows, but the impact is relatively small.

Recent data suggests that economic growth will lead to increased electricity demand. Job growth has been across all sectors and across the province, not strictly in the GTA. Broad based job growth across sectors and regions signifies a more sustainable and balanced economic growth pattern. This makes it more robust and less susceptible to shocks or cycles. Manufacturing employment growth and increased factory orders for goods signify growth in the industrial sector which will have a more direct impact on energy demand.

Canada continues to have great economic fundamentals that will help encourage economic expansion. Despite potential increases to interest rates in the near future, they still remain historically low. Inflation is not a threat and debt levels for consumers and business are generally manageable. Add in a low Canadian dollar and strong U.S. economy and Ontario is positioned to see strong export demand. However, there remains significant downside risk.

The renegotiation of NAFTA would not impact all provinces equally. Ontario would be vulnerable to protectionist measures that would inhibit the trade of manufactured goods. Fortunately, Canada has endeavored to expand its export markets with the CETA and TPP. However, the benefits of those agreements are a number of years off while the negative aspects of renegotiating NAFTA could be closer at hand.

**Actual Weather and Demand**

Since the last Ontario Demand Forecast document was published, actual demand reported for the six months of December through May was down 1.7 percent over the same period a year earlier. After adjusting for changes in the weather and the additional leap year day in last year's data, the growth rate is relatively unchanged at -1.6 percent.

For the past six months, distributor loads have dropped by 1.9 percent compared to the same months a year earlier. Distributor loads see the direct impact of conservation and the growth in embedded generation production, which contributes to the year-over-year drop. Once again, after adjusting for weather and the leap day, the year-over-year change was a reduction of 1.3 percent.

Wholesale customers' consumption decreased by 1.2 percent. Here the impact of the leap day is a little more pronounced and the adjusted change is a 0.6 percent decline. Declines in the pulp and paper sector accounted for much of the decline whereas the other sectors remained fairly flat.

The 2016-17 winter peak demand occurred on December 15, which was the third coldest day of the month. Both January and February were milder than normal and January's coldest days were buried on a weekend. Thus the winter peak landed in December for the first time since the winter of 2005-06. In both cases, the weather-corrected winter peak was pushed back to the following January indicating it was a function of January's mild weather.

The weather over the course of the spring was a bit of a mixed bag. March and May were cooler than normal while April was warmer than normal. Additionally, the amount of precipitation set records across the province. The peak occurred in March which is typical in spring unless there is a hot spell at the end of May. Since spring peaks can be either cold- or warm-weather driven, the timing of weather plays a key role. In the case of spring 2017, the cold temperatures of early March (-8.1°C) had a much bigger impact than the warm temperatures of late May (29.6°C). This seems to be the pattern over the last couple of years as the winter weather has been mild – particularly at the beginning of winter – with cold weather drifting into early spring. Recent spring weather has been cooler than normal.

**Demand Forecast**

In the 18-Month Outlook, the impacts of conservation, embedded generation and prices are incorporated into the demand forecast, resulting in reducing demand. Conversely, demand response programs are included in this analysis as a resource under the category of demand measures. Load modifiers – conservation, embedded generation and prices – and demand measures are discussed in section 4.4 of this document.

Table 1 summarizes the annual peak and energy demand forecast for the period covered in this 18-month forecast. Summer peaks are expected to continue their downward trajectory over the forecast. Though winter peaks will face downward pressure from gains in lighting efficiency and embedded wind generation, summer peaks will face greater downward pressure from numerous sources – improved air conditioning efficiency, the expanded Industrial Conservation Initiative (ICI) impacts and growth in solar embedded generation.

Grid-supplied energy demand is expected to show a small decrease in 2016 as weak actual demand through the first part of the year impacts the growth rate. An improving economy and increased industrial activity is expected to lead to a small rebound in 2018.

**Table 1: Peak and Energy Demand Forecast**

| Season | Normal Weather Peak (MW) | Extreme Weather Peak (MW) |
|---|---|---|
| Summer 2017 | 22,493 | 24,880 |
| Winter 2017-18 | 21,727 | 22,884 |
| Summer 2018 | 22,381 | 24,709 |
| **Year** | **Normal Weather Energy (TWh)** | **% Growth in Energy** |
| 2006 | 152.3 | -1.9% |
| 2007 | 151.6 | -0.5% |
| 2008 | 148.9 | -1.8% |
| 2009 | 140.4 | -5.7% |
| 2010 | 142.1 | 1.2% |
| 2011 | 141.2 | -0.6% |
| 2012 | 141.3 | 0.1% |
| 2013 | 140.5 | -0.6% |
| 2014 | 138.9 | -1.1% |
| 2015 | 136.2 | -1.9% |
| 2016 | 136.2 | 0.0% |
| 2017 (Forecast) | 135.4 | -0.6% |
| 2018 (Forecast) | 136.4 | 0.7% |

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## Caution and Disclaimer

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# 1.0 Introduction

## 1.1 Outlook Documents

The Ontario Electricity Market Rules (Chapter 5 Section 7.1) require that a demand forecast for the next 18 months be produced and published on a quarterly basis. This Ontario Demand Forecast meets this requirement and covers the period from July 2017 to December 2018. It supersedes the previous forecast released in March 2017 and the previous Ontario Demand Forecast document released in December 2016.

## 1.2 Demand Forecast Document

This document provides an 18-month forecast of electricity demand for Ontario, based on the stated assumptions and using the methodology described in the document "Methodology to Perform Long-Term Assessments," found on the IESO website at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2017jun.pdf. Readers may envision other scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgement in considering possible future scenarios. This forecast provides a base upon which changes in assumptions can be considered.

Ontario demand is the sum of coincident loads plus the losses on the IESO-controlled grid. This demand forecast was based on actual demand, weather and economic data through the end of March 2017. Data for April and May have been incorporated into the tables and figures of this document. This document is divided into the following sections:

Section 2.0 summarizes the forecast results

Section 3.0 looks at historical demand

Section 4.0 describes the assumptions used in this forecast of electricity demand.

All the tables in this report are contained in the 18-Month Outlook Tables (http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlooktables_2017jun.xls) spreadsheet posted alongside the Outlook documents. The spreadsheet's historical tables contain data back to market opening, which would not be practical in a printed document.

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

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

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# 2.0 Demand Forecast

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

Table 2.1 contains the forecast of system weekly peak, energy demand and the load forecast uncertainty (LFU) for the weekly peak. The LFU is a measure of variability in load due to the volatility of weather. Figures 2.1 and 2.2 show the historical weekly energy and peak demand along with the projected forecast.

**Table 2.1: Weekly Peak and Energy Demand Forecast**

| Week Ending | Normal Peak (MW) | Extreme Peak (MW) | Load Forecast Uncertainty (MW) | Normal Energy Demand (GWh) | Week Ending | Normal Peak (MW) | Extreme Peak (MW) | Load Forecast Uncertainty (MW) | Normal Energy Demand (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| 02-Jul-17 | 22,058 | 23,891 | 1,016 | 2,642 | | | | | |
| 09-Jul-17 | 22,493 | 24,880 | 814 | 2,740 | 08-Apr-18 | 17,836 | 18,373 | 471 | 2,489 |
| 16-Jul-17 | 22,099 | 23,805 | 838 | 2,772 | 15-Apr-18 | 17,095 | 18,065 | 496 | 2,433 |
| 23-Jul-17 | 21,892 | 23,787 | 1,035 | 2,669 | 22-Apr-18 | 16,648 | 16,875 | 531 | 2,392 |
| 30-Jul-17 | 21,931 | 24,614 | 841 | 2,754 | 29-Apr-18 | 16,650 | 17,036 | 721 | 2,371 |
| 06-Aug-17 | 22,376 | 24,569 | 958 | 2,774 | 06-May-18 | 17,533 | 20,176 | 849 | 2,344 |
| 13-Aug-17 | 21,966 | 24,628 | 985 | 2,728 | 13-May-18 | 17,377 | 19,714 | 845 | 2,358 |
| 20-Aug-17 | 21,241 | 24,385 | 1,362 | 2,704 | 20-May-18 | 18,508 | 21,795 | 1,175 | 2,386 |
| 27-Aug-17 | 21,389 | 23,409 | 1,413 | 2,707 | 27-May-18 | 18,333 | 21,986 | 1,330 | 2,334 |
| 03-Sep-17 | 20,508 | 23,043 | 1,370 | 2,590 | 03-Jun-18 | 19,082 | 21,502 | 1,292 | 2,416 |
| 10-Sep-17 | 18,922 | 22,219 | 680 | 2,437 | 10-Jun-18 | 19,744 | 24,008 | 1,055 | 2,561 |
| 17-Sep-17 | 19,328 | 21,001 | 781 | 2,501 | 17-Jun-18 | 20,625 | 24,098 | 835 | 2,576 |
| 24-Sep-17 | 18,088 | 20,105 | 420 | 2,469 | 24-Jun-18 | 22,314 | 24,304 | 754 | 2,641 |
| 01-Oct-17 | 17,373 | 18,629 | 554 | 2,411 | 01-Jul-18 | 22,162 | 23,995 | 1,016 | 2,680 |
| 08-Oct-17 | 17,633 | 17,667 | 786 | 2,448 | 08-Jul-18 | 22,211 | 24,709 | 814 | 2,662 |
| 15-Oct-17 | 17,451 | 17,591 | 507 | 2,429 | 15-Jul-18 | 22,381 | 23,640 | 838 | 2,750 |
| 22-Oct-17 | 17,677 | 18,114 | 392 | 2,466 | 22-Jul-18 | 21,731 | 23,629 | 1,035 | 2,647 |
| 29-Oct-17 | 17,837 | 18,358 | 318 | 2,507 | 29-Jul-18 | 21,764 | 24,448 | 841 | 2,730 |
| 05-Nov-17 | 17,985 | 18,711 | 416 | 2,519 | 05-Aug-18 | 22,225 | 24,418 | 958 | 2,751 |
| 12-Nov-17 | 19,108 | 19,678 | 601 | 2,625 | 12-Aug-18 | 21,843 | 24,500 | 985 | 2,710 |
| 19-Nov-17 | 19,398 | 20,189 | 342 | 2,643 | 19-Aug-18 | 20,983 | 24,281 | 1,362 | 2,687 |
| 26-Nov-17 | 19,839 | 20,625 | 607 | 2,716 | 26-Aug-18 | 21,215 | 23,234 | 1,413 | 2,687 |
| 03-Dec-17 | 20,248 | 21,329 | 409 | 2,765 | 02-Sep-18 | 20,355 | 22,900 | 1,370 | 2,575 |
| 10-Dec-17 | 20,408 | 21,607 | 555 | 2,792 | 09-Sep-18 | 18,805 | 22,097 | 680 | 2,421 |
| 17-Dec-17 | 20,909 | 21,832 | 690 | 2,836 | 16-Sep-18 | 19,193 | 20,869 | 781 | 2,485 |
| 24-Dec-17 | 20,671 | 21,749 | 362 | 2,805 | 23-Sep-18 | 17,924 | 19,961 | 420 | 2,454 |
| 31-Dec-17 | 20,422 | 21,566 | 528 | 2,711 | 30-Sep-18 | 17,255 | 18,513 | 554 | 2,399 |
| 07-Jan-18 | 21,154 | 22,056 | 570 | 2,844 | 07-Oct-18 | 17,479 | 17,520 | 786 | 2,431 |
| 14-Jan-18 | 21,727 | 22,884 | 547 | 2,912 | 14-Oct-18 | 17,309 | 17,344 | 507 | 2,412 |
| 21-Jan-18 | 21,297 | 21,939 | 483 | 2,900 | 21-Oct-18 | 17,526 | 17,961 | 392 | 2,450 |
| 28-Jan-18 | 21,136 | 22,113 | 404 | 2,905 | 28-Oct-18 | 17,692 | 18,206 | 318 | 2,490 |
| 04-Feb-18 | 21,133 | 22,284 | 734 | 2,911 | 04-Nov-18 | 17,940 | 18,609 | 416 | 2,505 |
| 11-Feb-18 | 20,351 | 21,820 | 635 | 2,847 | 11-Nov-18 | 18,918 | 19,484 | 601 | 2,605 |
| 18-Feb-18 | 20,076 | 21,475 | 581 | 2,797 | 18-Nov-18 | 19,214 | 20,008 | 342 | 2,621 |
| 25-Feb-18 | 19,717 | 21,489 | 501 | 2,745 | 25-Nov-18 | 19,664 | 20,450 | 607 | 2,696 |
| 04-Mar-18 | 20,306 | 21,533 | 531 | 2,774 | 02-Dec-18 | 20,068 | 21,158 | 409 | 2,741 |
| 11-Mar-18 | 19,770 | 20,598 | 649 | 2,730 | 09-Dec-18 | 20,224 | 21,428 | 555 | 2,771 |
| 18-Mar-18 | 18,702 | 19,397 | 611 | 2,653 | 16-Dec-18 | 20,756 | 21,682 | 690 | 2,819 |
| 25-Mar-18 | 18,255 | 19,009 | 569 | 2,564 | 23-Dec-18 | 20,541 | 21,621 | 362 | 2,806 |
| 01-Apr-18 | 18,145 | 19,113 | 567 | 2,509 | 30-Dec-18 | 20,112 | 20,911 | 528 | 2,649 |

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

**Figure 2.1: Weekly Energy Demand – History and Forecast**

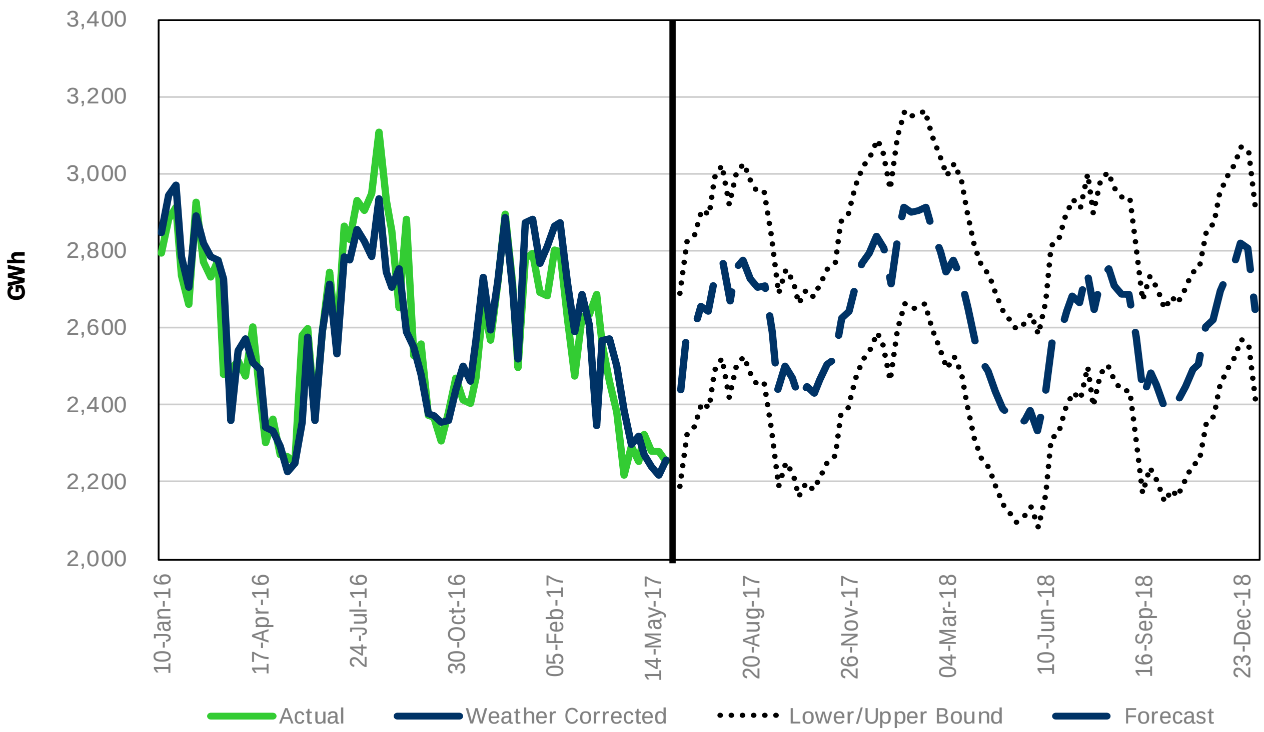
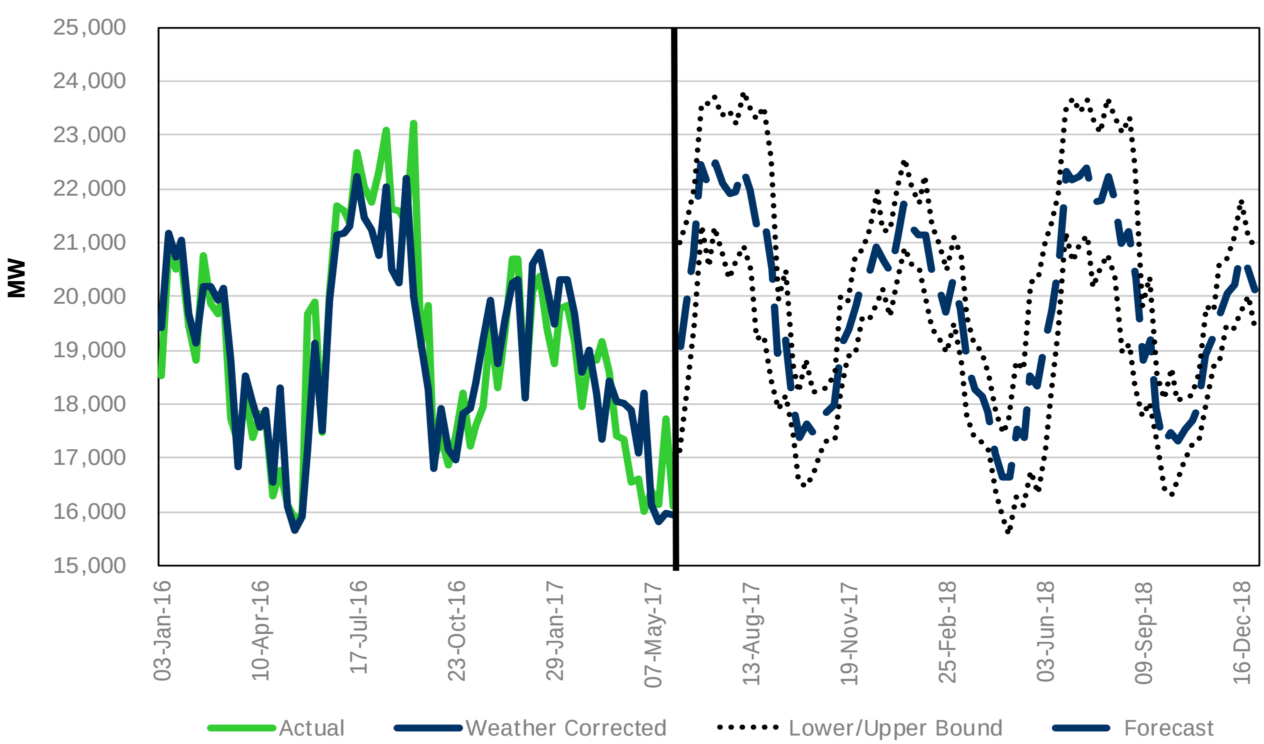



**Figure 2.2: Weekly Peak Demand – History and Forecast**

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# 3.0 Historical Review

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

## 3.1 Six-Month Review – December to May

Since the last Ontario Demand document, actuals have been recorded for the period December to May. The winter of 2016-17 was milder than normal and the spring of 2017 was generally milder and wetter than normal.

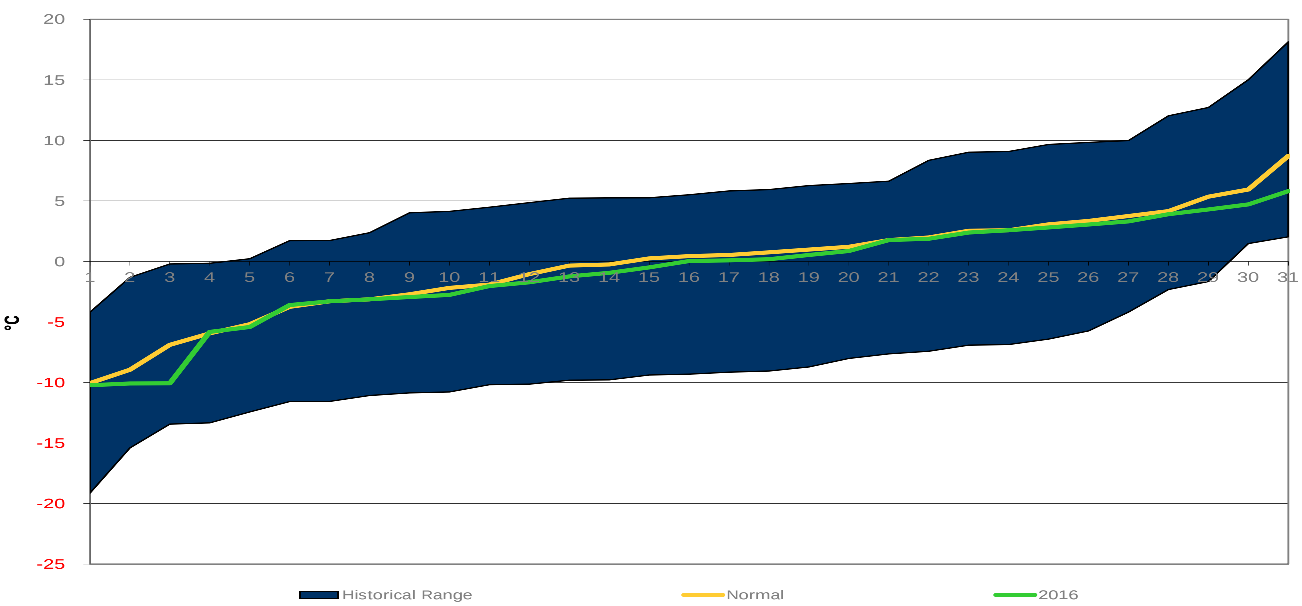
The winter peak came from December (20,688 MW) and the spring peak came from March (19,174 MW). Both were lower than the previous seasons.

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

December

December 2016 was very close to normal, both on average and peak. Figure 3.1 presents the ranked range of temperatures for the month, from coldest to warmest. The values for the month were consistently normal based on the history (1970 to present).

**Figure 3.1: Daily Temperature - December**




The peak demand occurred mid-month on December 15. At times, December peaks can be impacted by the holidays, but in this case the weather over the holidays was very mild. The peak occurred on the third coldest day of the month. The peak demand was 20,688 MW (20,299 MW weather-corrected) which is low by historical standards but consistent with the post-recession December values.

Monthly energy demand was 11.9 terawatt-hours (TWh) and 11.9 TWh weather-corrected. The actual was an increase over the previous year which was historically mild. However, the weather-corrected value was the lowest since market opening.

Minimum demand for the month was 11,684 MW, occurring during the early hours of December 27. This is the product of mild weather and the holidays.

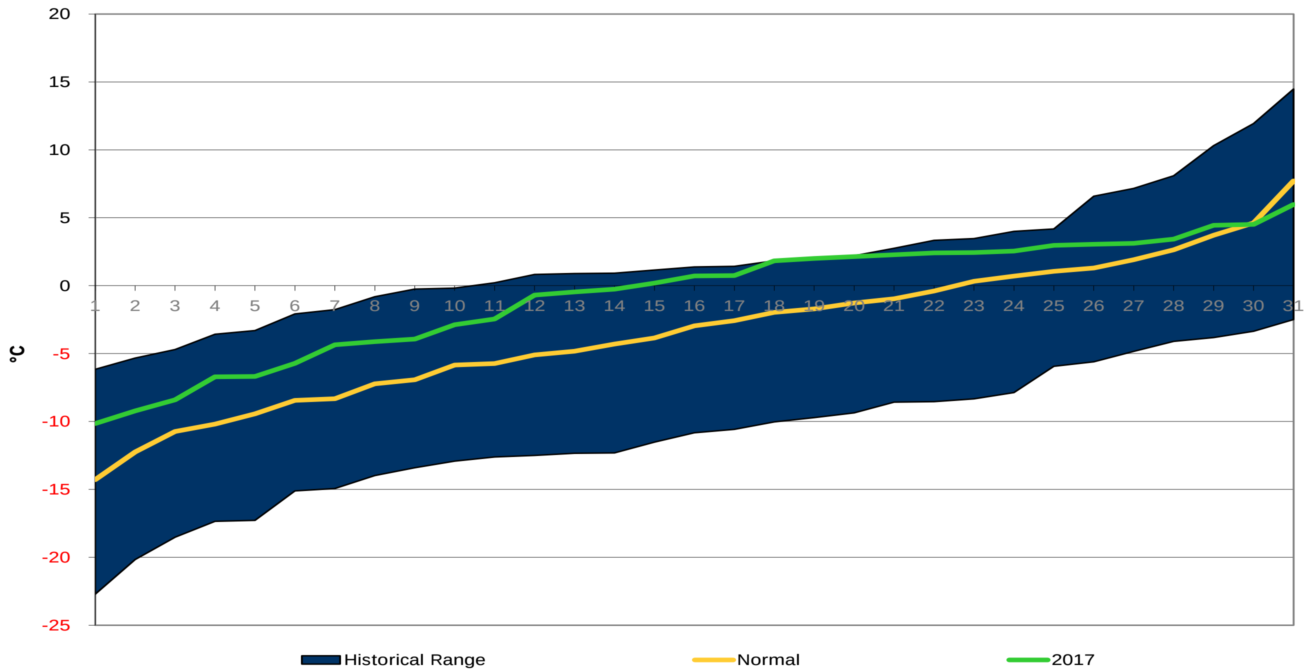
Embedded generation for the month was 446 GWh, a 0.8-percent increase over the previous December. Both solar and wind production was up with non-contracted generation falling compared to the previous year.

Wholesale customers' load showed year-over-year growth of 1.0 percent compared to the previous December.

## January

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

**Figure 3.2: Daily Temperature - January**




The peak occurred on January 9, which was the eighth coldest day of the month. It was a Monday and followed the coldest day of the month. The actual peak was 20,372 MW, and the weather-corrected peak was a higher 20,830 MW. Once again these values are low by historical standards and consistent with the post-recession period.

Energy demand for the month was 12.1 TWh (12.5 TWh weather-corrected). Both of these figures represent the lowest January energy demand since market opening.

Minimum demand for the month was 12,246 MW, which was higher than last year. The minimum occurred at 5 a.m. on a Sunday.

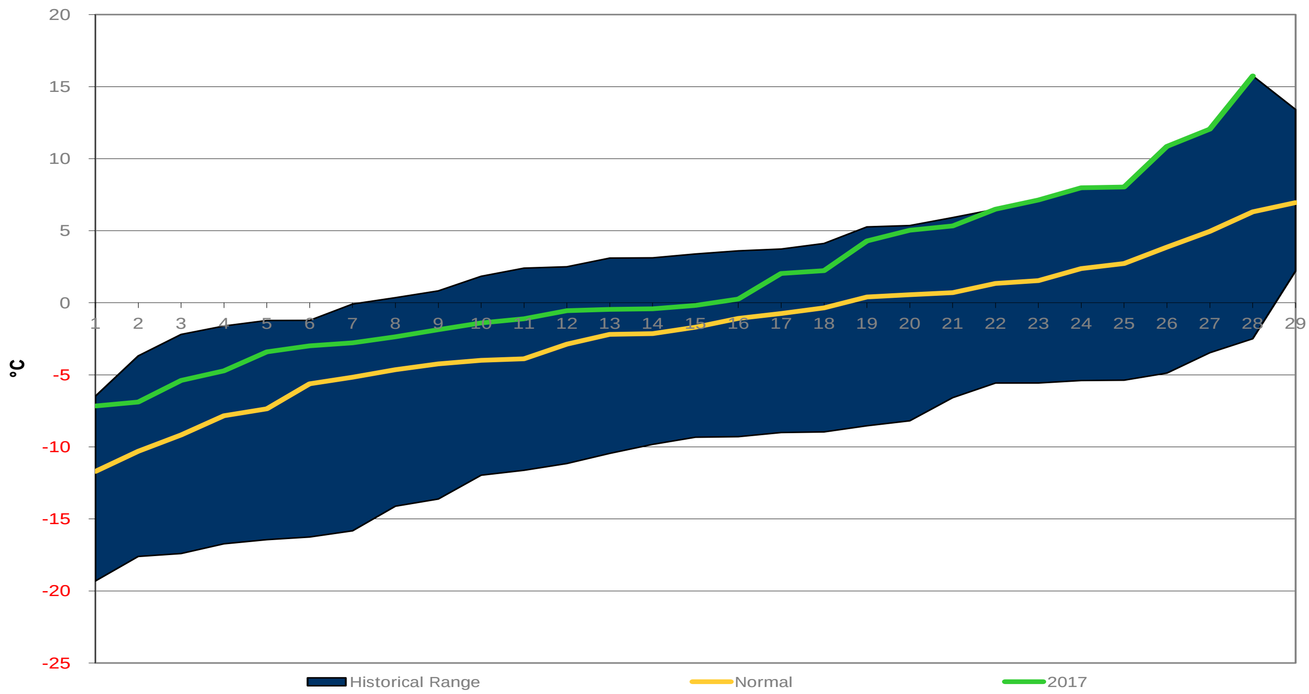
Embedded generation for the month was 472 gigawatt-hours (GWh), a 0.8-percent decrease over the previous January. Solar output fell dramatically (-14%), while wind output was up an even more dramatic 46%.

Wholesale customers' consumption decreased by a 1.0 percent compared to January 2015, reversing the trend of the positive growth for the previous two months.

## February

February was significantly milder than normal. Figure 3.3 shows the February 2017 temperature relative to history.

**Figure 3.3: Daily Temperature - February**




The month's peak occurred on the seventh coldest day of the month, February 7. The peak was 20,766 MW and 20,195 MW weather-corrected. These numbers are consistent with the observations for February since the recession.

Energy demand for the month was 10.6 TWh (11.0 TWh weather-corrected). This is consistent with the downward trend since the recession and represents the lowest February values since market opening.

The minimum demand was 11,867 MW for the month. Last February was the first time that the minimum fell below 13,000 MW, so this represents a new low for the month by a significant margin. The minimum did occur on an extremely mild weekend with daily temperatures in excess of 10°C.

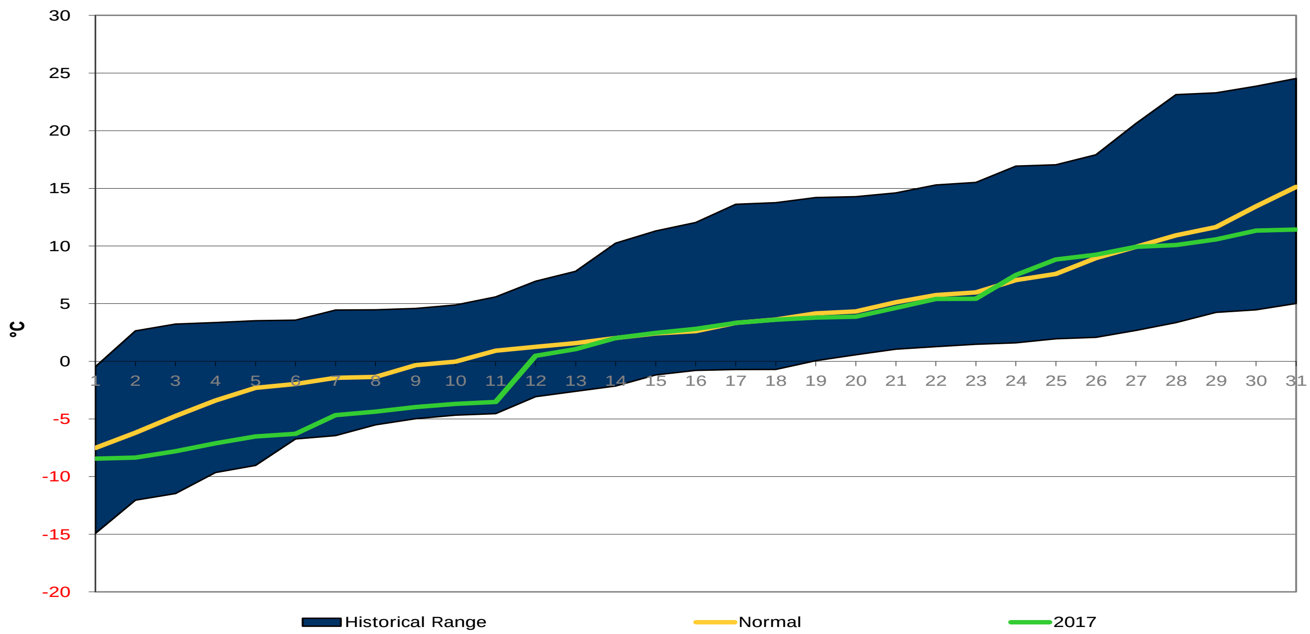
Embedded generation for the month was 493 GWh and represented a 2.1 percent increase over the previous February. The growth rate rises to 5.8% after adjusting for additional leap year day in 2016. Both solar and wind were down compared to the previous February.

Wholesale customers' consumption declined in February by 3.0% compared to February 2016. However all of this was due to the additional leap day in 2016. Adjusting for the day would translate into a 0.4% increase in wholesale customers' consumption.

## March

The weather for March was colder than normal with the peak temperatures near normal. Figure 3.4 shows the March 2017 temperatures against the historical range.

**Figure 3.4: Daily Temperature - March**




The actual peak of 19,174 MW occurred on March 14, the third coldest day of the month. The two coldest days fell on the weekend. In fact, it was colder at the time of the March peak than it was for either the January or February peak. The weather-corrected peak was 18,742 MW. Both actual and weather-corrected peaks were historic lows for the month.

Energy demand for the month was 11.6 TWh and 11.4 TWh weather-corrected. The weather-corrected energy was the lowest for March since the market opened. The low values are being impacted by the increased conservation savings and the embedded generation output.

Minimum demand for the month was 12,158 MW, which was actually a reversal of recent experience, and is consistent with post-recession experience. The minimum occurred at 2 a.m. on a Sunday morning.

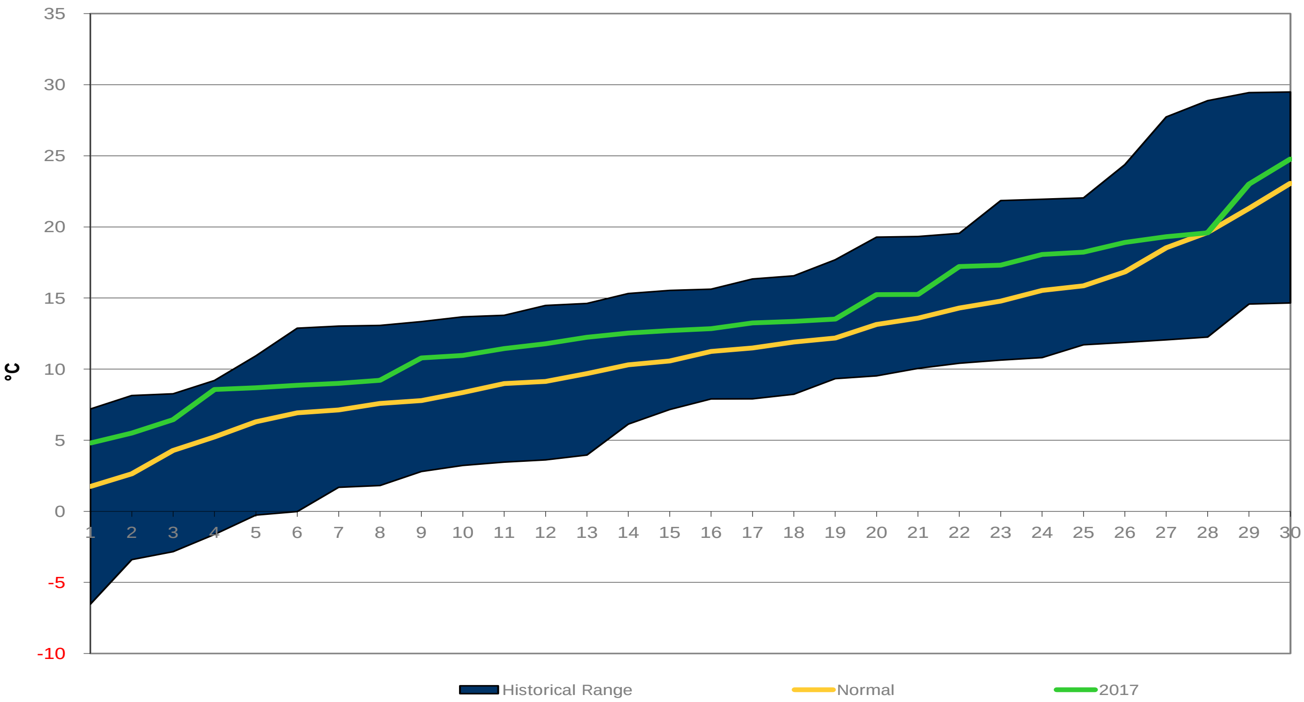
Embedded generation for the month was 568 GWh, an increase of 5.9 percent over the previous March. There was strong growth in both solar and wind output.

Wholesale customers' consumption was up 1.7% over the previous March. This is overstating the level of activity as March 2016 included Easter whereas March 2017 did not and would have had an extra work day.

## April

April was warmer than normal and also very wet. It was the wettest April for many locations across the province. As well, Ontario received as much snow in April as it did in March. Figure 3.5 illustrates the temperatures of April 2016 against the historical range.

**Figure 3.5: Daily Temperature - April**




The month's peak demand occurred on April 6, which was the second coldest day of the month. By historical standards the temperature was warm for April. The actual peak was 17,349 MW which was the lowest April peak since market opening being slightly lower than April 2010. The weather-corrected value was higher at 18,217 MW. Both values are consistent with the post-recession time period.

Actual energy demand for the month was 9.8 TWh and represents the first time any month has been less than 10 TWh. The weather corrected value was 10.1 TWh. Both actual and weather-corrected were all-time lows.

The minimum demand of 10,167 MW occurred at 4 a.m. on a Sunday April 16. This was the perfect conditions for a minimum value as it was Easter Sunday and significantly warmer than normal.

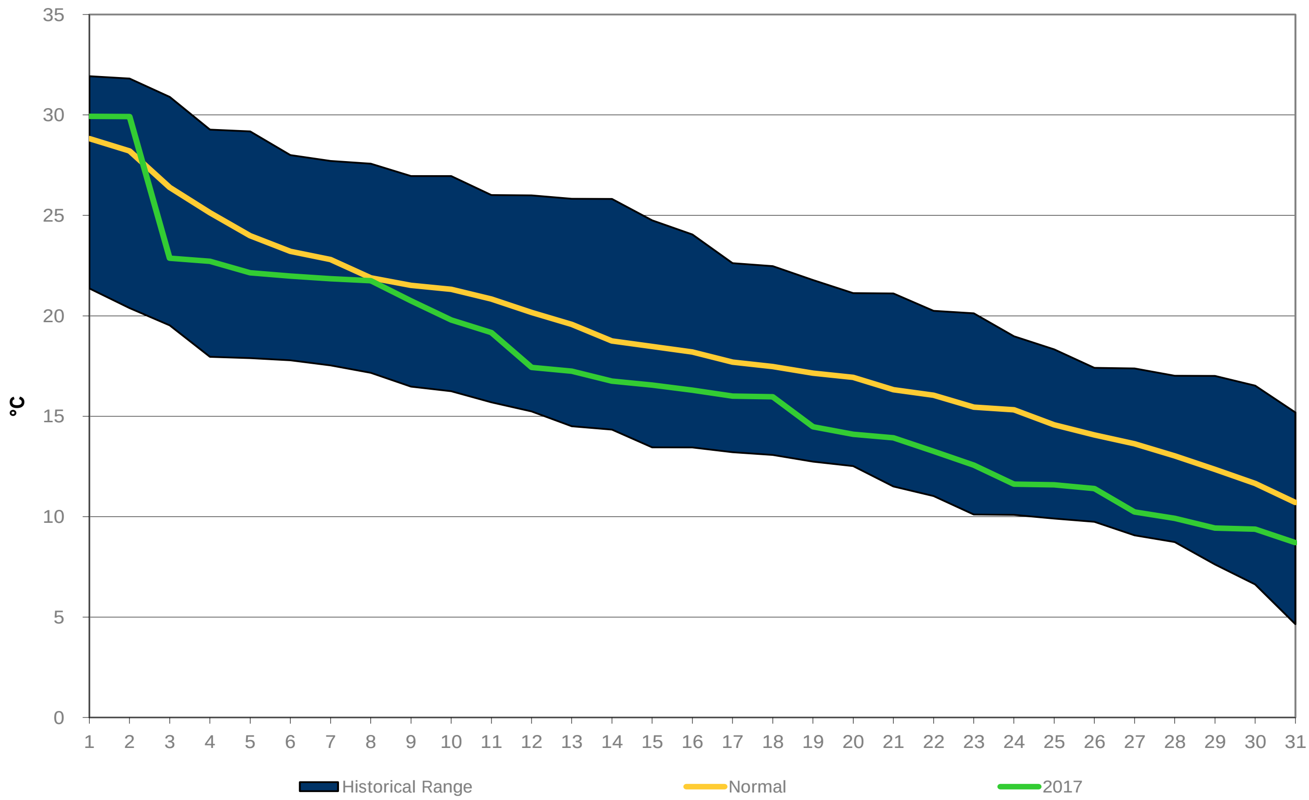
Embedded generation for the month was 604 GWh. This represents a slight 9.6-percent decrease over the previous April. Despite all the rain, solar output was actually up over the previous April. Likewise wind production also increased year over year. The decline stemmed from a drop in non-contract generation and hydroelectric output.

Wholesale customers' consumption dropped 5.1 percent over the previous April. As a converse to March, April 2017 included the Easter weekend whereas April 2016 did not. The additional holiday weekend would impact the level of activity this April.

## May

May was cooler than normal and much wetter normal. Many cities had more rain than any time in the past 50 years.

**Figure 3.6: Daily Temperature - May**




The actual peak for May was 17,738 MW occurring on Thursday, May 18. It was the second warmest day of the month. The weather-corrected value was virtually the same at 17,764 MW. The actual peak was the lowest since the recession.

The impacts of conservation and embedded generation mean that the energy demand for the month has been fairly flat since the recession but trending downward. Actual demand for the month was 10.2 TWh and weather-corrected energy demand was slightly lower at 10.1 TWh. Both are historical lows for May.

Minimum demand of 10,249 MW occurred Sunday, May 21 at 3 a.m. This is the lowest May minimum since market opening.

Embedded generation topped 632 GWh for the month, which represents a decrease of 6.8 percent compared to the previous May. Increases in wind, hydro and biofuel output were offset by solar and non-contracted embedded generation.

The wholesale customers' consumption fell 0.6 percent compared to the previous May. Motor vehicle manufacturing was up but most other major sectors had shown a decline.

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

Table 3.1 contains a summary of the weather and demand for the past six months.

**Table 3.1: Historical 2016-2017 Weather and Demand Summary**

| Historical Analysis | | December | January | February | March | April | May |
|---|---|---|---|---|---|---|---|
| **Actual Weather** | Average Temperature (°C) | 0.3 | 0.2 | 2.6 | 2.8 | 13.4 | 16.2 |
| | Minimum Temperature (°C) | -8.1 | -9.3 | -5.0 | -8.1 | 4.4 | 6.9 |
| | Maximum Temperature (°C) | 5.7 | 6.2 | 17.4 | 15.3 | 25.3 | 29.6 |
| **Normal Weather** | Normal Average Temperature (°C) | 0.2 | -3.3 | -1.5 | 3.6 | 10.7 | 17.1 |
| | Normal Minimum Temperature (°C) | -8.4 | -13.5 | -13.5 | -5.5 | 2.8 | 8.7 |
| | Normal Maximum Temperature (°C) | 10.0 | 6.7 | 8.2 | 16.7 | 25.0 | 27.2 |
| **Actual Demand** | Peak Demand (MW) | 20,688 | 20,372 | 19,838 | 19,174 | 17,349 | 17,738 |
| | Average Hour (MW) | 16,060 | 16,274 | 15,785 | 15,579 | 13,595 | 13,839 |
| | Minimum Hour (MW) | 11,684 | 12,246 | 11,867 | 12,158 | 10,167 | 10,745 |
| | 90th Percentile (MW) | 18,666 | 18,425 | 18,065 | 17,608 | 15,576 | 15,675 |
| | Percent above 20,000 (MW) | 1.4% | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% |
| | # of Hours Above 20,000 (MW) | 10 | 2 | 0 | 0 | 0 | 0 |
| | Energy Demand (GWh) | 11,948 | 12,108 | 10,608 | 11,591 | 9,789 | 5,979 |
| **Weather Corrected Demand** | Peak Demand (MW) | 20,299 | 20,830 | 20,306 | 18,986 | 18,217 | 17,764 |
| | Energy Demand (GWh) | 11,923 | 12,537 | 10,970 | 11,324 | 10,171 | 10,064 |
| **Forecast Demand** | Peak Demand (MW) | 20,888 | 21,914 | 20,966 | 20,137 | 17,970 | 19,193 |
| | Energy Demand (GWh) | 12,431 | 12,819 | 11,295 | 11,824 | 10,367 | 10,577 |

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

## 3.2 Historical Energy Demand

The six-month period can be broken down into its two main components, winter (December, January and February) and spring (March, April and May).

The weather over the winter was milder than normal. Compared to the previous winter energy demand was down 1.5%. If you adjust for the weather and the additional leap year day the decline was a 1.3% or 0.5 TWh.

Distributors' loads have declined by 1.7 percent over the winter compared to last winter. After making the weather and leap year adjustments, the decline remains 1.7%. This reduction is a result of growth in embedded generation output, conservation savings and economic structural change. Over the course of the winter, embedded generation was 1.4 TWh, an increase of 0.9 percent over the previous year.

For the winter months, wholesale loads showed a decrease of 1.0 percent compared to the previous winter. However, that becomes a virtually flat once adjusted for the additional leap day.

For the spring, demand was 2.0 percent lower than the previous year and a nearly identical -1.9% decline after adjusting for weather. The distributor loads showed an actual decline of 2.0-percent and a 1.9-percent decline after correcting for weather.

Wholesale customers' loads decreased by 1.3 percent compared to the previous spring. The declines stem from decreases in the pulp and paper sector.

Figure 3.7 shows weather-corrected distributor load and embedded generation output. Though embedded generation shows seasonal volatility, the underlying upward trend is quite evident in the graph. Annual embedded generation output was 6.3 TWh in 2016 an increase of 4.6% over 2015. The growth rate has slowed in concert with the growth in capacity.

For the six months from December to May, distributors' loads declined by 1.9 percent compared to the same six-month period a year earlier. Embedded generation declined by a same 1.9 percent for the same period.

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

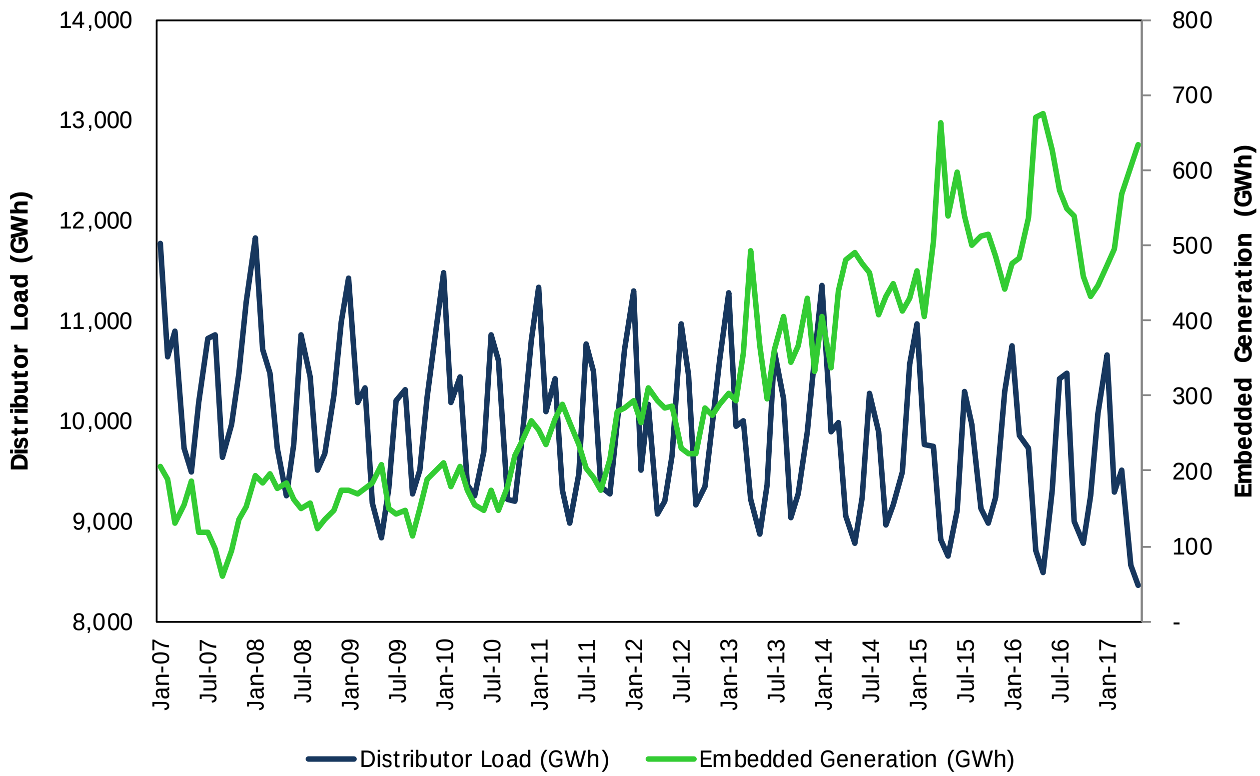



Figure 3.8 shows the year-over-year change in wholesale customers' average hourly consumption. The graph traces the impact of the recession, the short and modest recovery in 2010 and the up and down nature since.

Figure 3.9 shows the wholesale customers' highest monthly average hourly load by industry segment for each of 2008, 2015, 2016 and 2017 year to date.

Mining is the only sector that is higher than its pre-recession value. Pulp and paper has shown the greatest decline. The other sectors show a similar pattern of having fallen from the pre-recession values and appear to have found a new equilibrium that has been more or less stable over the past four years.

The changing industrial structure is due to a variety of causes. Some changes are sector specific – the impact of the decline in demand for newsprints on pulp and paper – while other changes are broad-based – such as the appreciation of the Canadian dollar from 2004 through to 2014. Wholesale loads declined by 24 percent in 2009. Since then loads have shown a very slight increase.

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

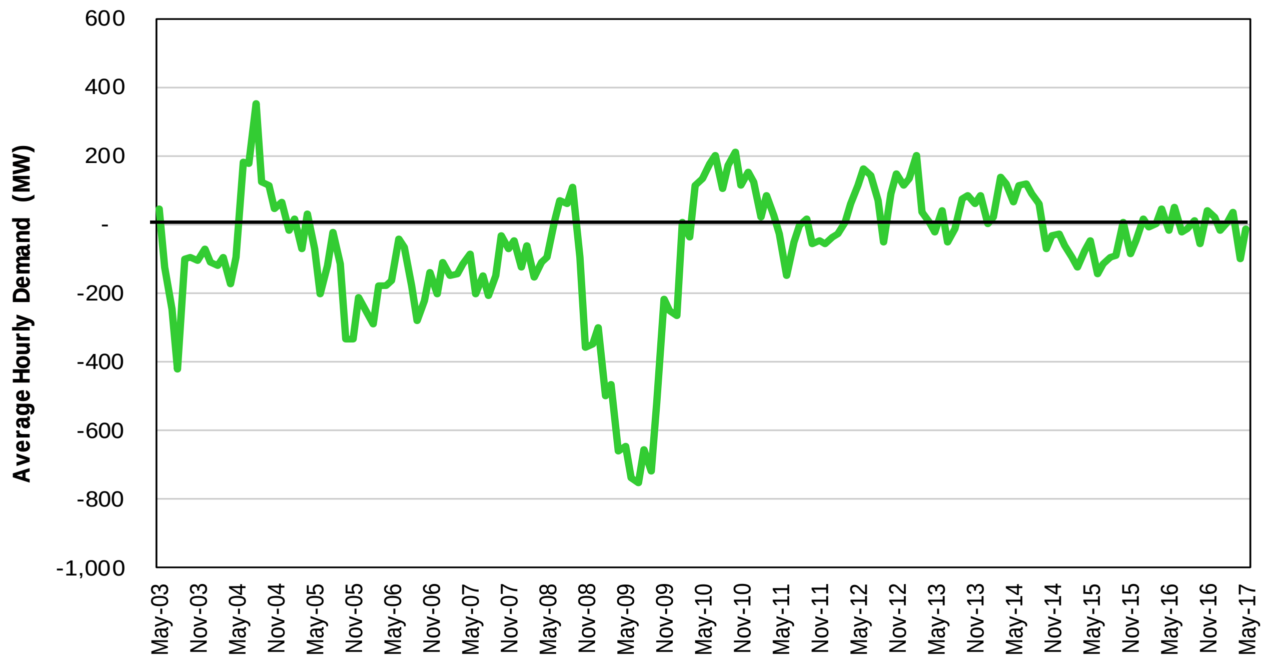



**Figure 3.9: Wholesale Customers' Average Hourly Consumption by Industry Segment**

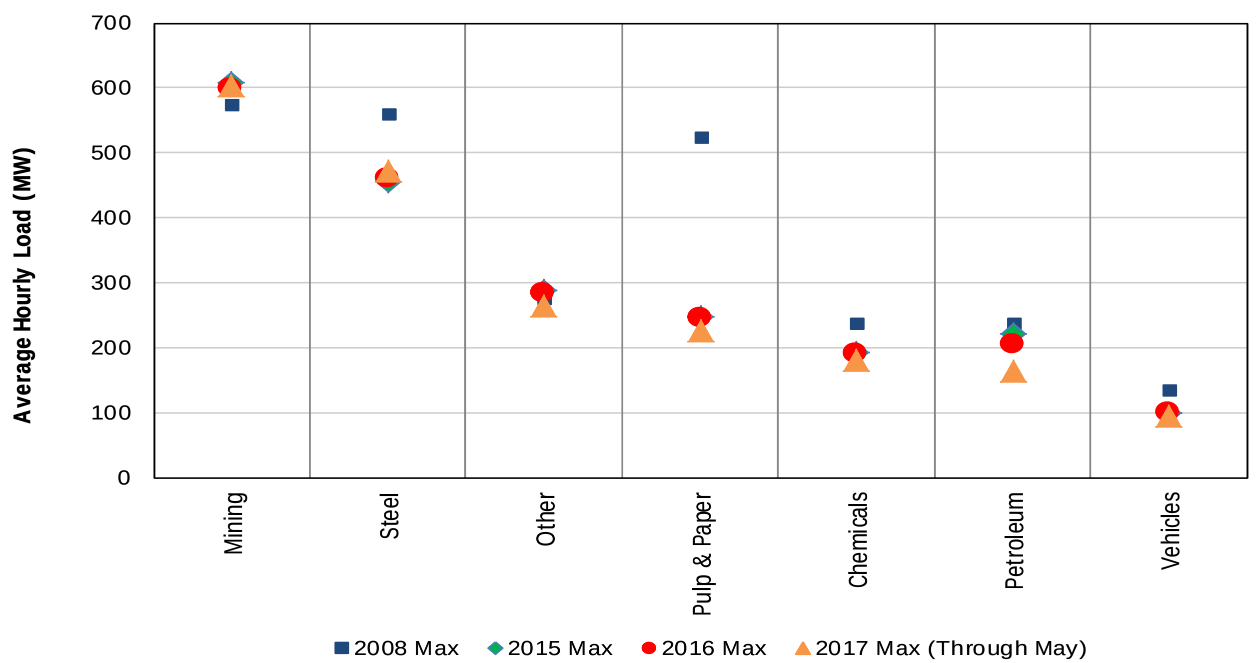



Table 3.2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week and notes any item of significance for the week. If the weather-corrected

demand is greater than the actual demand, it means that the actual weather was milder than normal. Additional history is available in the 18-Month Outlook Tables spreadsheet in Table 3.3.1.

**Table 3.2: Historical Weekly Energy Demand**

| Week Number | Week Ending | Peak Day | Actual Energy (GWh) | Corrected Energy (GWh) | Notes |
|---|---|---|---|---|---|
| 48 | 04-Dec-16 | 28-Nov-16 | 2,567 | 2,592 | |
| 49 | 11-Dec-16 | 09-Dec-16 | 2,720 | 2,724 | |
| 50 | 18-Dec-16 | 15-Dec-16 | 2,896 | 2,886 | |
| 51 | 25-Dec-16 | 19-Dec-16 | 2,718 | 2,703 | Christmas Day |
| 52 | 01-Jan-17 | 28-Dec-16 | 2,496 | 2,517 | Boxing Day & New Years Day |
| 1 | 08-Jan-17 | 05-Jan-17 | 2,778 | 2,873 | |
| 2 | 15-Jan-17 | 09-Jan-17 | 2,795 | 2,884 | |
| 3 | 22-Jan-17 | 17-Jan-17 | 2,690 | 2,768 | |
| 4 | 29-Jan-17 | 24-Jan-17 | 2,684 | 2,811 | |
| 5 | 05-Feb-17 | 30-Jan-17 | 2,804 | 2,865 | |
| 6 | 12-Feb-17 | 07-Feb-17 | 2,795 | 2,875 | |
| 7 | 19-Feb-17 | 16-Feb-17 | 2,626 | 2,719 | |
| 8 | 26-Feb-17 | 21-Feb-17 | 2,474 | 2,591 | Family Day |
| 9 | 05-Mar-17 | 02-Mar-17 | 2,629 | 2,689 | |
| 10 | 12-Mar-17 | 10-Mar-17 | 2,633 | 2,606 | |
| 11 | 19-Mar-17 | 14-Mar-17 | 2,686 | 2,346 | |
| 12 | 26-Mar-17 | 22-Mar-17 | 2,559 | 2,566 | |
| 13 | 02-Apr-17 | 30-Mar-17 | 2,461 | 2,570 | |
| 14 | 09-Apr-17 | 06-Apr-17 | 2,383 | 2,500 | |
| 15 | 16-Apr-17 | 12-Apr-17 | 2,217 | 2,384 | Good Friday |
| 16 | 23-Apr-17 | 20-Apr-17 | 2,294 | 2,297 | Easter Monday |
| 17 | 30-Apr-17 | 25-Apr-17 | 2,254 | 2,321 | |
| 18 | 07-May-17 | 04-May-17 | 2,324 | 2,268 | |
| 19 | 14-May-17 | 08-May-17 | 2,280 | 2,238 | |
| 20 | 21-May-17 | 18-May-17 | 2,277 | 2,218 | |
| 21 | 28-May-17 | 25-May-17 | 2,253 | 2,255 | Victoria Day |

## 3.3 Historical Peak Demand

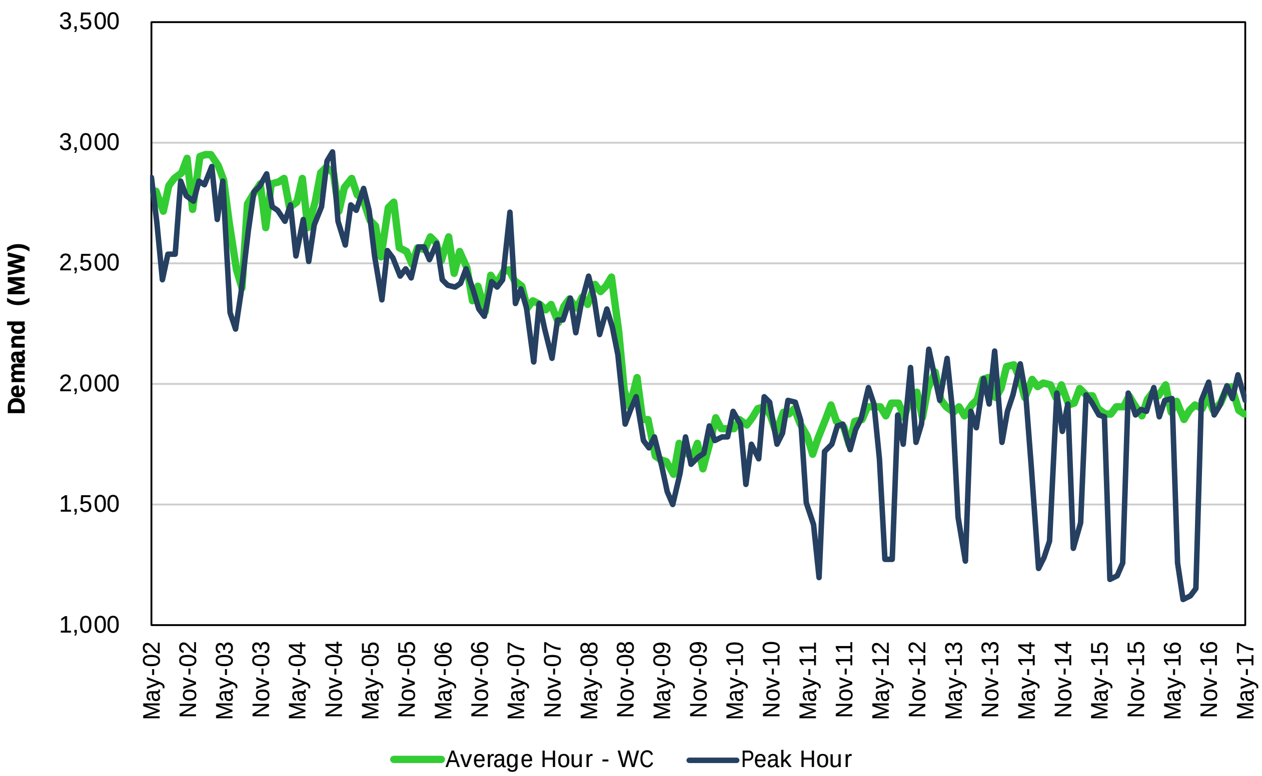
Peak demands are weather-driven, weekday events. Peak demands have been facing downward pressure due to a number of factors. Conservation, time-of-use rates, embedded generation, demand response, the Industrial Conservation Initiative (ICI) and economic restructuring have all contributed to lower peak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

The winter peak was 20,688 MW, which is lower than last winter's peak (20,836 MW). The peak weather was warmer than the previous winter. As well, the weather-corrected winter peak was lower than the previous one. The spring peak was 19,174 MW, which was also lower than the previous spring peak (20,063 MW). Even after adjusting for weather the spring 2017 peak was lower than the previous spring.

Figure 3.10 shows the wholesale customers' average hourly monthly demand and their consumption at the time coincident with the system peak. It is evident that prior to the ICI program, the average and coincident peak tracked quite closely as many operations operated 24/7. With the introduction of the program in 2010, wholesale customers have responded by reducing their load during the five peak days. The graph shows a portion of the response as the program applies to Class A customers -- that includes wholesale customers and a number of customers served by distributors.

In 2017, the program was expanded to include customers with a peak load of 0.5 MW or higher. Additionally, for those with an average peak load in excess of 1 MW, the NAIC code restrictions were lifted. Previously, participants were restricted to manufacturing sectors.  This change will enable large commercial facilities access to the program. Those between 0.5 MW and 1 MW are still restricted to specific sectors: manufacturing, greenhouses and floriculture.

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




For most years, the province has been summer peaking, but the summer peaks face more downward pressure than the winter peaks. In particular, conservation and embedded solar generation do not impact the seasonal peaks to the same degree. The summer peak is primarily driven by air conditioning load, whereas the winter peak is a result of a mix of end uses. As such, conservation programs that increase air conditioner efficiency and improve the building envelope will have a direct impact on summer peak. The winter peak is mostly impacted through conservation initiatives that improve lighting efficiency, and the resulting impact on the winter peak is smaller. The second factor is embedded solar generation. Since the winter peak occurs after sunset, the output of embedded solar will be zero and have no impact on the winter peak. The summer peak occurs during daylight hours when embedded solar output is significant. This is reducing the summer peaks but is also having an impact of pushing the summer peaks later in the day.

Traditionally, the summer peak occurred in the late afternoon as air conditioners worked to dispel the accumulated heat. Now the embedded solar is "carving out" demand in the middle of the day and having the effect of pushing the peak later in the day when solar output is declining more rapidly than demand.

Figure 3.11 shows the winter weekday peaks levels in MW and the hour in which they occurred for the winter of 2005 and the winter of 2016. The graph clearly shows how peaks are lower today – a result of conservation and lower industrial load – but that the peaks occur in the same timeframe from hours 18-20. Figure 3.12 shows the weekday peaks in MW and the hour in which they occurred for the summer of 2005 and 2016. Here the peaks are once again lower but in the case of the summer, the hours at which those peaks are occurring have changed. Generally, the peaks have shifted to later in the day. The contrast between the summer and winter distribution of peak hours shows the impact that embedded solar in having on the summer peaks. Embedded solar is making the summer peaks lower and later in the day.

**Figure 3.11: Seasonal Weekday Peak Hour Distribution - Winter**

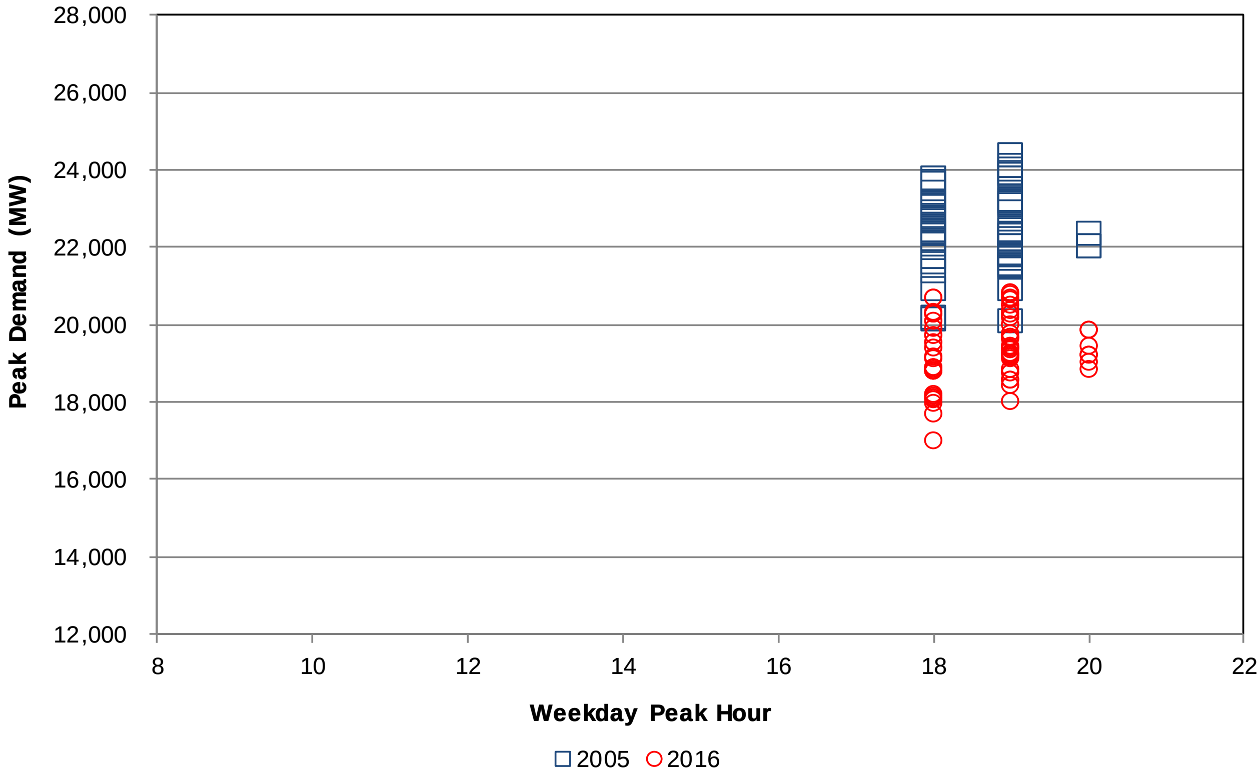
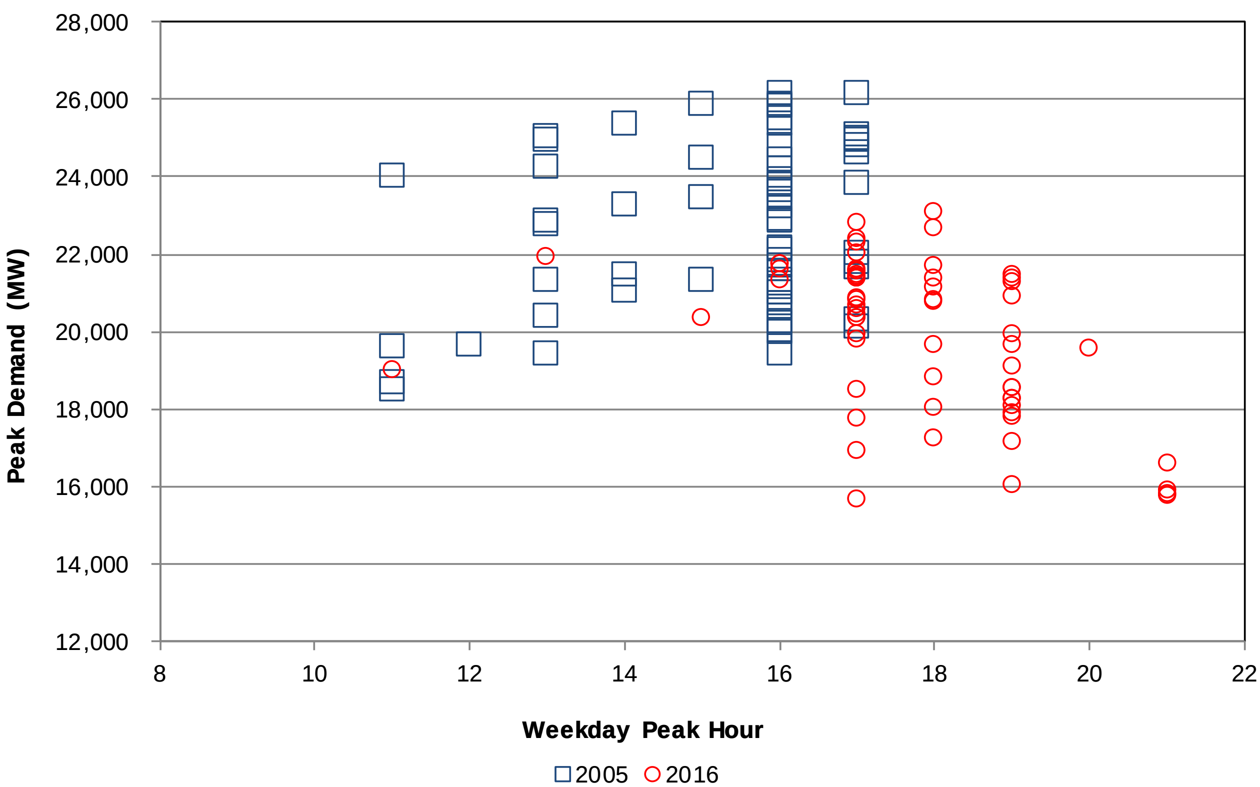



**Figure 3.12: Seasonal Weekday Peak Hour Distribution – Summer**



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

Figure 3.13 shows the break-down for the past two summer and winter peaks. For the past two winters ICI has not been a factor. As well, for all of the seasonal peaks depicted there was no demand response activated. Generally, the embedded generation is higher during the summer peak as the significantly larger solar capacity doesn't impact the winter peak which occurs after dark. However, the 2016-17 winter peak had a very high level of embedded generation output as it was extremely windy on the peak day.

**Figure 3.13: Anatomy of Seasonal Peaks**

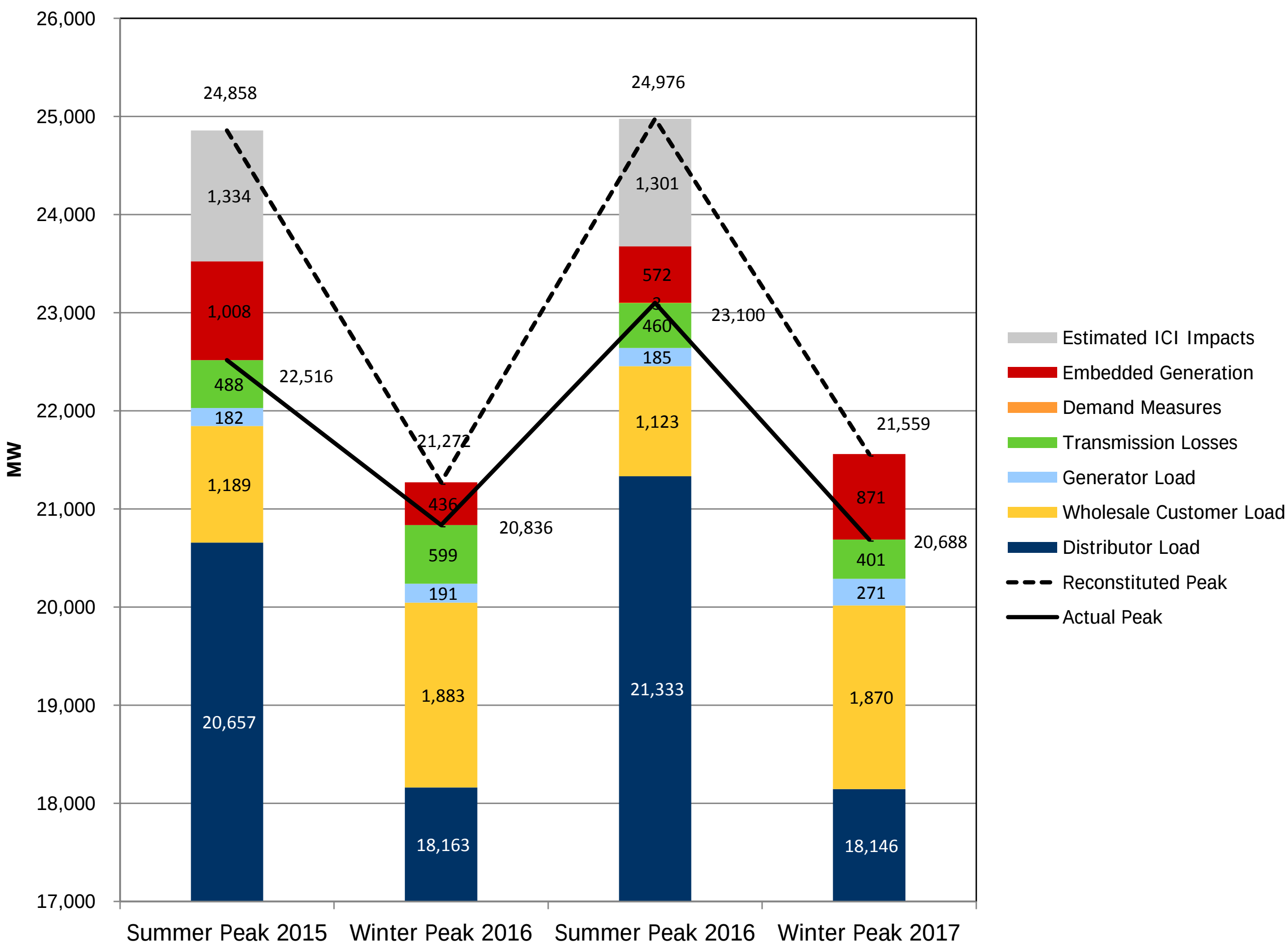


Table 3.3 shows the actual and weather-corrected weekly peak demand for the past six months.

**Table 3.3: Historic Weekly Peak Demand**

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

## 3.4 Load Duration Curves

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

The figures are not weather-corrected so the weather will influence the shape of each of the graphs. The spring and fall load duration curves are more heavily influenced by the level of economic activity than by the weather. Those load duration curves show that demand remains low by historical standards.

**Figure 3.14: Spring Load Duration Curve**

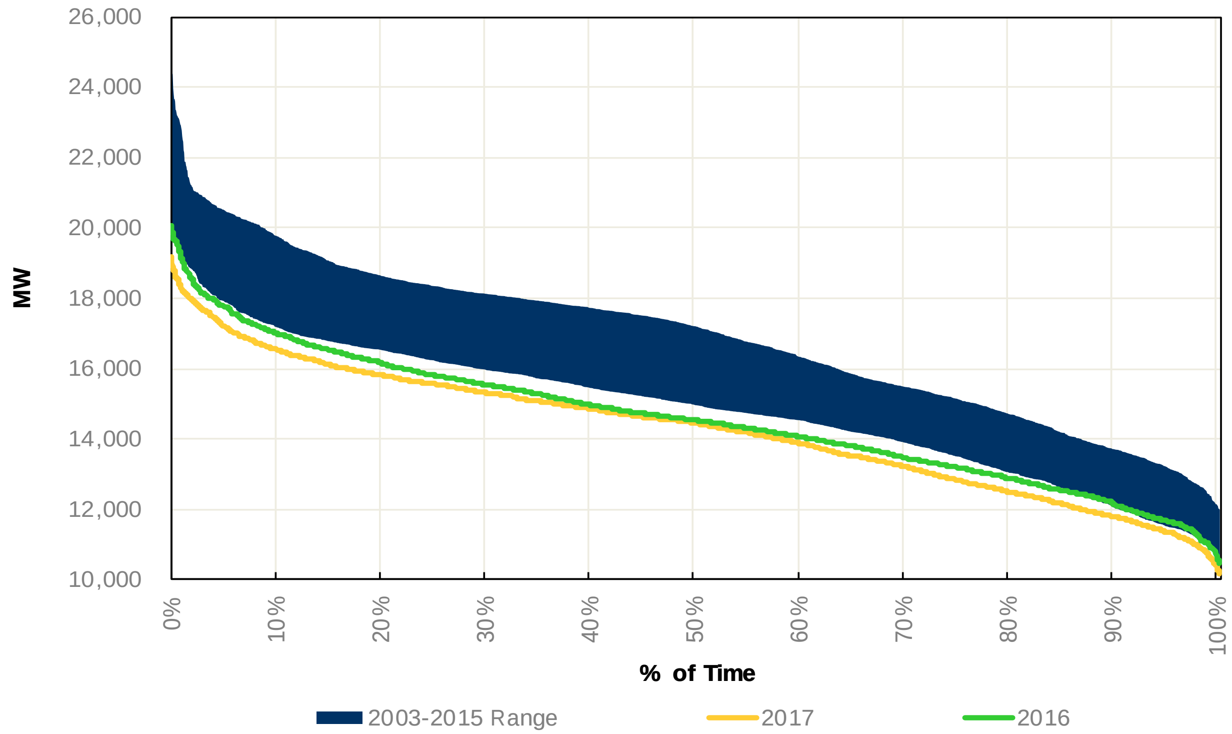



**Figure 3.15: Winter Load Duration Curve**

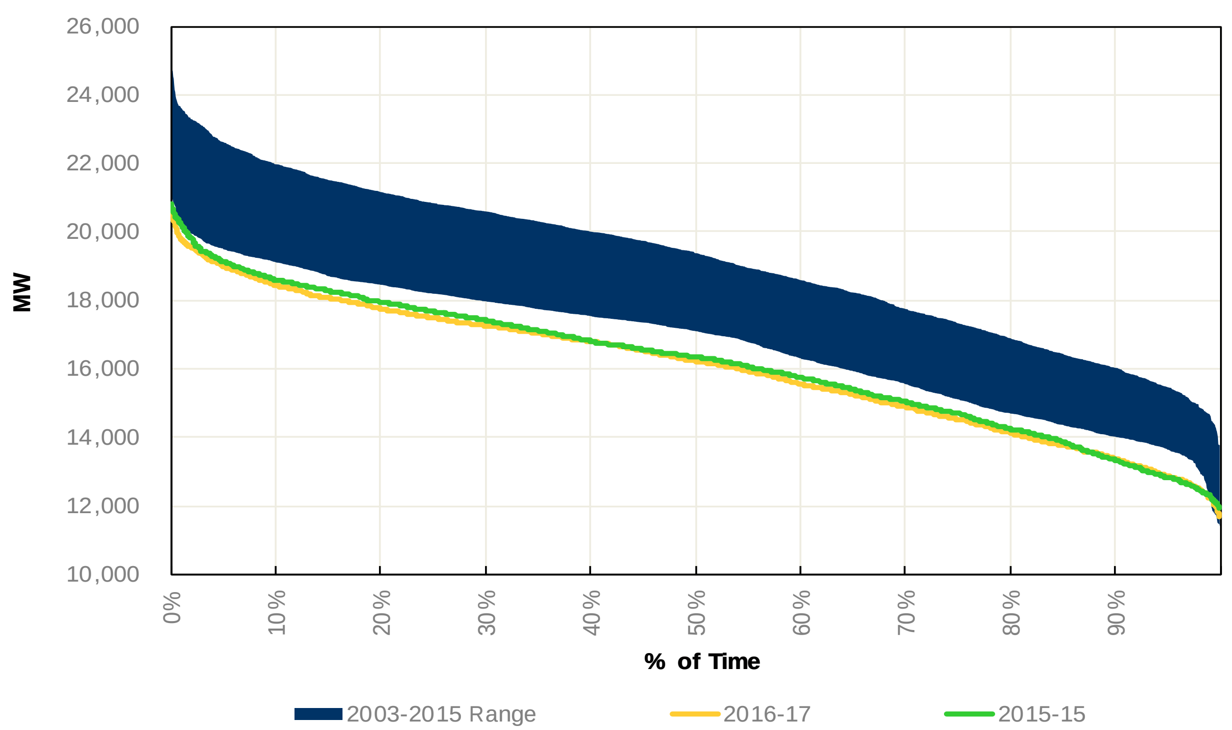


**Figure 3.16: Fall Load Duration Curve**

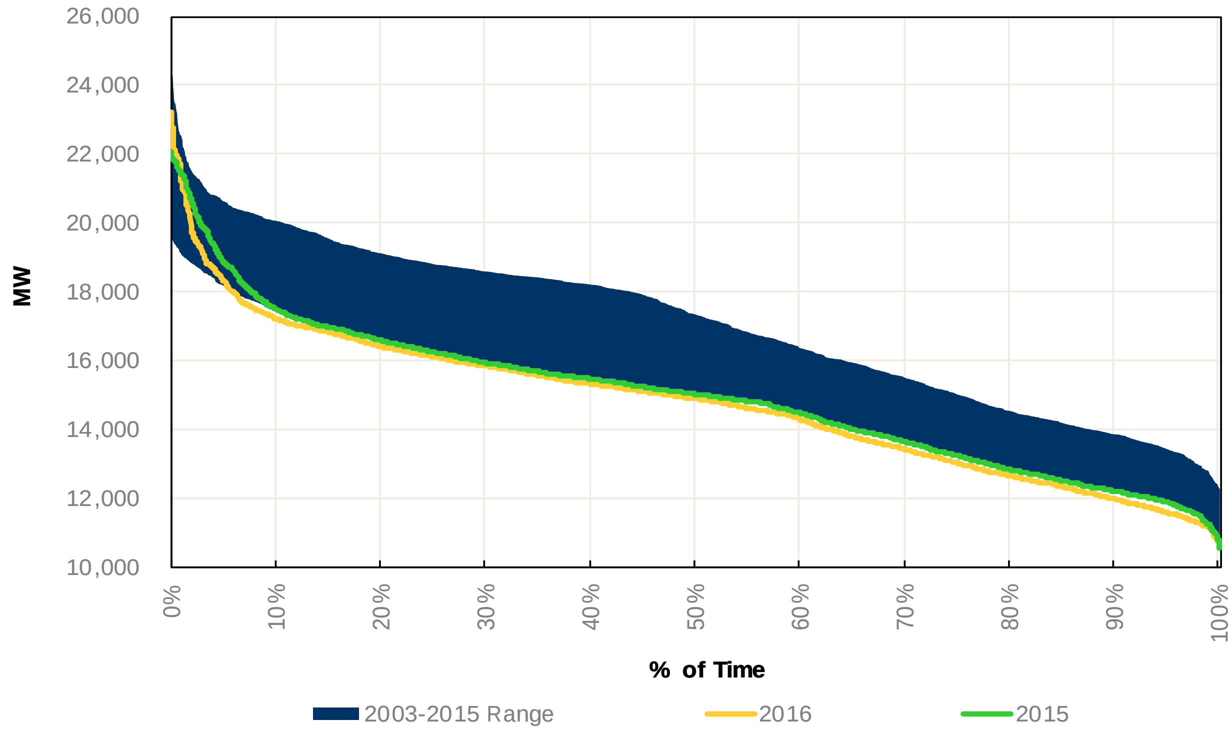
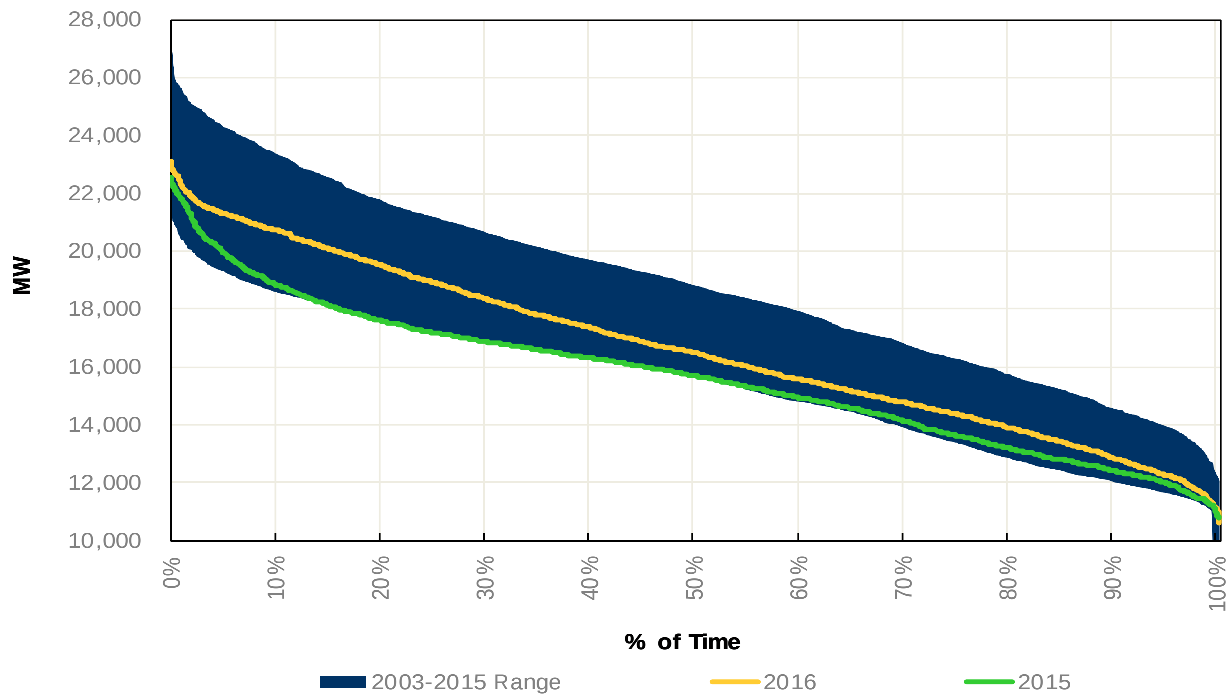



**Figure 3.17: Summer Load Duration Curve**



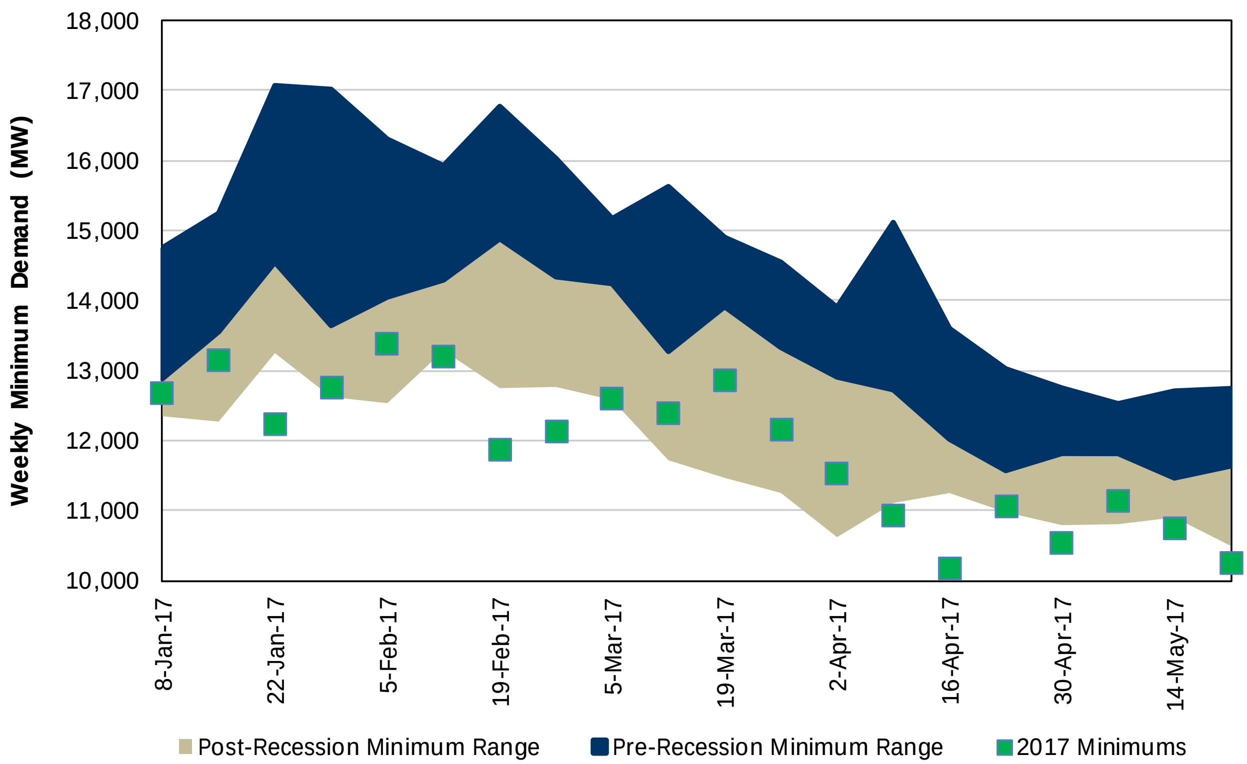
## 3.5 Historical Minimum Demand

Like peak demands, the minimums are driven by weather, calendar and economic effects, which, of the drivers, is most important varies throughout the seasons. The winter, spring and fall have the potential for heating load, whereas the summer period has the potential for cooling loads. Minimums continue to establish new lows in the post-recession era due to lower industrial loads, conservation and increased embedded generation. In the case of minimums that occur during the early predawn hours, it is embedded wind that is further reducing the need for grid-supplied electricity. In fact, some load points with high quantities of embedded wind actually push power back onto the grid overnight when embedded wind output is high.

Figure 3.18 shows the minimum weekly demands for the period January to May since market opening. The dark band represents the range of values for the years 2002 – 2008 while the lighter band shows the post-recession minimums for the 2009 to 2016 time frame. The squares represent the weekly minimums for the past six months.

The minimums of the past six months reflect the generally mild weather. Numerous times in 2017 the weekly minimums were reaching new lows. This is due to the aforementioned combination of impacts – embedded generation, conservation, mild weather and the level of overnight economic activity. The weekly minimums occur during the early morning hours of the weekend, when the level of economic activity is lowest.

**Figure 3.18: Weekly Minimum Demands**




**- End of Section -**

# 4.0 Forecasting Process and Assumptions

A detailed description of the forecasting methodology can be found in the document entitled "Methodology to Perform Long-Term Assessments" found on the IESO web site at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2017jun.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.

Canada has had strong economic fundamentals since the recession – low interest rates, a strong financial sector and a rich resource base – despite this, Canada has not experienced strong growth in the post-recession recovery period. Much of that is a reflection of the overall global situation as Canada is a trade dependent nation. Strong fundamentals at home cannot outweigh the declining demand from our trading partners who were experiencing sluggish growth.

The economic climate bodes well for central Canada's export-oriented manufacturing sector. Strong U.S. growth means there is a market for Canada's goods. Lower commodity prices mean the cost of inputs has declined. Finally, a lower dollar means exports will be more competitively priced. All this lays the ground work for improved economic activity in Ontario. Recent economic data suggests that Ontario's economy and its manufacturing base are showing increased strength.

There are a significant number of downside risks to the economic outlook. In particular, trade-based disputes surrounding the renegotiation of NAFTA could derail Ontario's economic trajectory. With the CETA and TPP, Canada is diversifying its export markets as to not be so U.S. dependent. However, those expanded markets will not shield the Ontario economy of any US/Canada trade issues in the near term.

Table 4.1 summarizes the key economic drivers for the demand forecast. The Ontario growth index is a weighting of the economic drivers as they relate to demand.

**Table 4.1: Forecast of Ontario Economic Drivers**

| Year | Ontario Employment | | Ontario Housing Starts | | Ontario Growth Index | |
|---|---|---|---|---|---|---|
| | Thousands | Annual Growth (%) | Thousands | Annual Growth (%) | Index | Annual Growth (%) |
| 2001 | 5,921 | 2.1 | 70.3 | 4.2 | 1.150 | 1.88 |
| 2002 | 6,034 | 1.5 | 79.6 | 13.3 | 1.169 | 1.65 |
| 2003 | 6,213 | 3.1 | 80.9 | 1.7 | 1.198 | 2.49 |
| 2004 | 6,314 | 1.7 | 79.9 | -1.3 | 1.219 | 1.81 |
| 2005 | 6,381 | 1.3 | 73.2 | -8.4 | 1.236 | 1.39 |
| 2006 | 6,452 | 1.5 | 67.8 | -7.4 | 1.253 | 1.35 |
| 2007 | 6,545 | 1.6 | 62.8 | -7.4 | 1.271 | 1.41 |
| 2008 | 6,610 | 1.5 | 71.9 | 14.6 | 1.287 | 1.23 |
| 2009 | 6,433 | -2.7 | 47.9 | -33.3 | 1.276 | -0.85 |
| 2010 | 6,538 | 1.6 | 57.1 | 19.1 | 1.294 | 1.41 |
| 2011 | 6,658 | 1.8 | 65.2 | 14.3 | 1.314 | 1.60 |
| 2012 | 6,703 | 0.7 | 74.4 | 14.1 | 1.329 | 1.09 |
| 2013 | 6,823 | 1.8 | 58.6 | -21.2 | 1.348 | 1.49 |
| 2014 | 6,878 | 0.8 | 56.2 | -4.2 | 1.361 | 0.96 |
| 2015 | 6,923 | 0.7 | 68.3 | 21.6 | 1.375 | 1.00 |
| 2016 | 6,999 | 1.1 | 74.4 | 8.9 | 1.392 | 1.27 |
| 2017 (f) | 7,094 | 1.4 | 77.5 | 4.2 | 1.412 | 1.42 |
| 2018 (f) | 7,172 | 1.1 | 70.8 | -8.6 | 1.429 | 1.22 |

The IESO has highlighted the shifting patterns in Ontario's employment as a measuring stick for sustained growth. Since the recession, growth has been sector- or region-specific and not broad-based. To generalize, much of the growth was centered in the service sector and in the GTA.

Figure 4.1 shows the year-over-year change in employment for Ontario, the Toronto zone and all other zones combined. Broad-based growth would mean that both Toronto and the other zones would be enjoying similar job creation. For the period following the recession, Ontario's economy experienced fairly broad-based growth over the 2010-2011 timeframe. Since then, however, growth has been an "either/or" experience with either the GTA or the rest of the province dominating. The last twelve months have shown a more balanced job growth between the two sub-provincial areas.

Figure 4.2 shows the year-over-year changes in employment broken down into services, manufacturing and other goods (mining, construction, agriculture, forestry, etc.). As with the zonal growth, a more broad-based and sustainable growth pattern would have growth across all of the sub-sectors. Since the start of 2016, employment growth is showing signs of being across all sectors.

Both these graphs point to a more broad based employment pattern, across regions and sectors. This is indicative of a more sustained economic expansion. Together with strong underlying economic fundamentals of low inflation, low interest rates and a competitive dollar will help the Ontario economy to growth over the forecast horizon.

**Figure 4.1: Zonal Employment Growth**

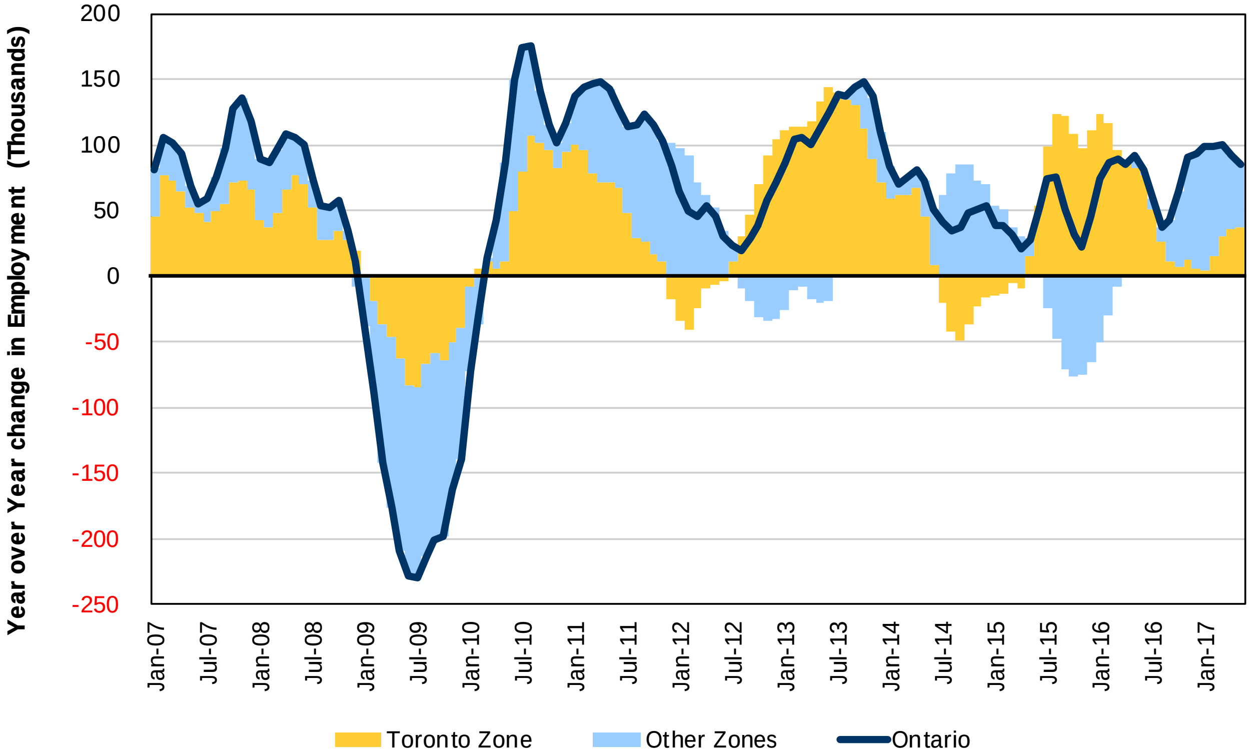
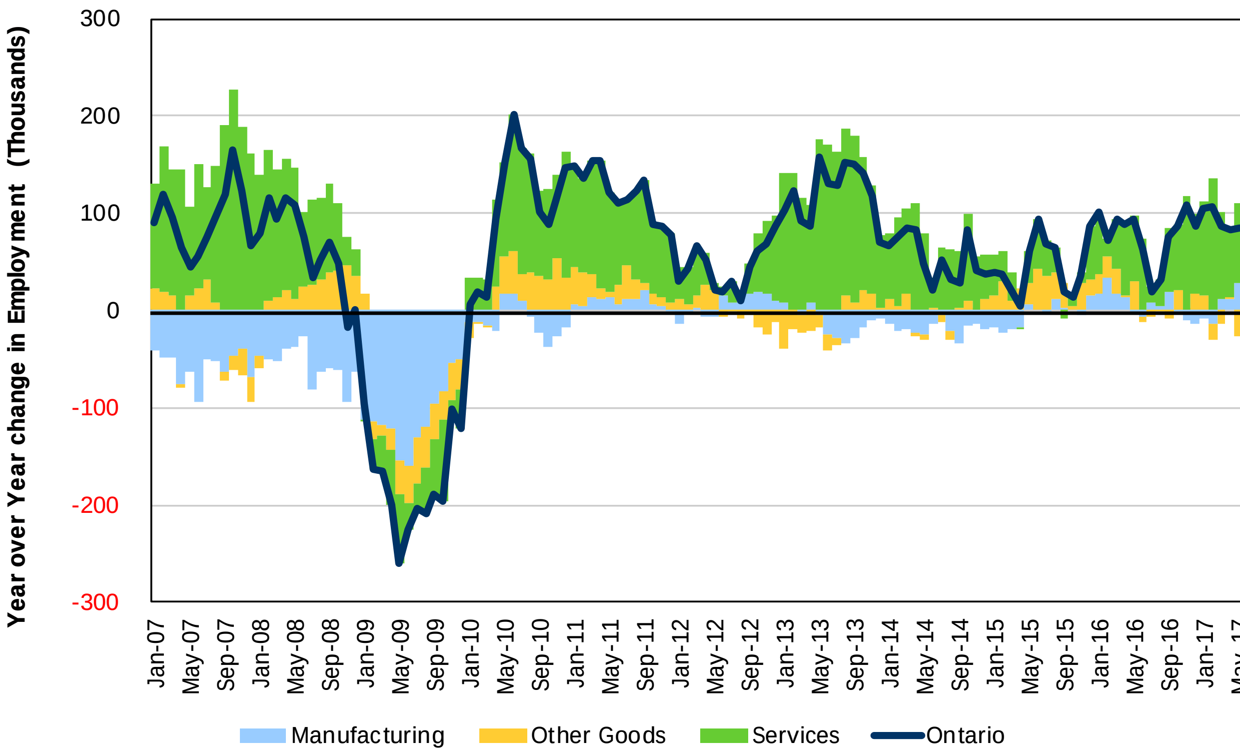



**Figure 4.2: Composition of Ontario's Employment Growth**



## 4.3 Weather Drivers for Forecast

Since forecasting long-term weather is not possible, weather scenarios are generated using historical data. The analytical studies that the IESO produces serve a variety of purposes and needs. As such, a variety of inputs are required. Therefore, the IESO produces demand forecasts based on a number of different weather scenarios. The most commonly utilized scenarios are Normal and Extreme.

The weather scenarios are generated using the following steps:

For each day over the past 31 years, a "weather factor" is calculated based on the weather conditions of that day (temperature, wind speed, cloud cover and humidity). This weather factor represents the MW impact on demand if those weather conditions were observed in the forecast horizon.

The daily weather factors are sorted from highest to lowest for each month.

Normal weather is based on the median value of the sorted weather factors across the 31 years of history. For example, the median value of the maximum weather factor from each January from 1980 to 2010 would be the first value for the normal January. The median value of the second highest weather factor from each January from 1980 to 2010 would be the second day in the normal January. This is repeated until all days in the month are generated. Once the normal months are created, they are mapped to the calendar based on the weekly average distribution of weather. The weekly peak-eliciting weather is always mapped to Wednesday to ensure that peaks do not occur on weekends or holidays.

Extreme weather is generated in a similar manner except that the maximum, rather than the median, value from the sorted 31-year history is used.

Load forecast uncertainty (LFU) -- a measure of demand fluctuations due to weather variability -- is a critical part of the analysis. In conjunction with the normal weather forecast, LFU is valuable in determining a distribution of potential outcomes under various weather conditions. The resource adequacy assessments use the Normal weather forecast in combination with LFU to consider a full range of peak demands that can occur under various weather conditions with varying probability of occurrence.

The Extreme weather scenario is valuable for studying situations where the system is under duress. Although the Extreme weather scenario is useful when examining peak conditions, it is unrealistic from an energy demand standpoint, as severe weather conditions do not persist over a long time period.

The 18-Month Outlook Tables spreadsheet includes Table 3.3.5, which has the Normal and Extreme weather scenarios. For each week, the table shows the historical weather used for the peak day of that week. The table shows the daily high (temperature) and wind speed. Not shown but used in forecasting demand are humidity and cloud cover. The IESO uses six weather stations in the demand models – the data in the table is for Toronto. The weather scenarios were updated for data through the end of December 2012.

## 4.4 Demand Measures and Load Modifiers

There are a number of initiatives and policies that have an impact on electricity demand. They can be grouped into two categories: demand measures and load modifiers. The rationale for the two categories is how they are treated with respect to the demand forecast. Demand measures are not incorporated into the demand forecast whereas the load modifiers are. In essence, demand measures are controllable while load modifiers are not. Demand measures include dispatchable loads, demand response programs and the peaksaver PLUS program. Load modifiers include conservation, prices and embedded generation.

### Demand Measures

Demand measures are dispatched like a generation resource. Whether you dispatch a gas plant to meet a level of demand or dispatch a load off to reduce that level of demand, the system is indifferent as supply equals demand. For the correct accounting of demand measures, they must be treated equitably on both sides of the ledger. Therefore, since demand measures are included in the supply mix to be dispatched off, demand must be forecasted at the higher level prior to demand measures. The historical demand is reconstituted to include load that was shed through the various demand response programs. Demand measures have no impact on the demand forecast.

### Load Modifiers -- Conservation

Conservation includes energy-efficiency programs, codes and standards and fuel switching. Projected conservation numbers are based on existing and future programs.

The impacts of conservation vary according to the program mix. For example, programs that promote increasing the efficiency of air conditioners will reduce the demand for electricity in summer but have no impact in the winter. Programs aimed at improving the insulation of building envelopes will impact electricity consumption year round.

Projected conservation impacts are incorporated into the demand forecast with the result of reducing forecasted demand.

### Load Modifiers -- Prices

Prices include the impact of time-of-use (TOU) rates and the Industrial Conservation Initiative (ICI). Both are factored into the demand forecast. As both are relatively new, information continues to be gathered and analyzed. The impact of these programs continues to evolve as market participants and consumers gain more experience and adjust their consumption.

TOU impacts will vary as rates are set. The overall impact will be to shift load within the day or week. Overall, peaks will be impacted more than energy in the short term. However, an increased awareness of electricity pricing will lead consumers to make equipment and usage decisions that can impact total electricity consumption in the future.

The ICI offers a financial incentive to participants who reduce their consumption at the time of the peak for the five highest peak days. The program runs from May to April. The ICI was expanded this year to allow customers with an average monthly peak demand greater than 500 kW and less than 1 MW who are in the manufacturing and greenhouse sectors. As well, those sector restrictions were lifted for customers with a peak greater than 1 MW. This will allow large commercial customers such as hospitals, universities and hotels to participate. Peak reductions have grown as both the number of participants have increased and the participants have improved their ability to identify and react to the peaks. First-year (2010) reductions were estimated at 200 MW, growing to an estimated 1,300 MW for the five peak days in 2016.

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

### Load Modifiers -- Embedded Generation

Embedded generation refers to load-displacing generation that is located on the market participants' side of the meter. This would include all generation under the Renewable Energy Standard Offer Program (RESOP), all generation under the microFIT program and some generation under the Green Energy Act's Feed-in Tariff (FIT). It also includes generators that are not contracted through the above programs. All output provided by embedded generation is an offset to grid-supplied electricity. Therefore, the impact of embedded generation is factored into the 18-month demand forecast as a reduction to demand.

For the forecast, embedded generation is split into groups according to fuel type: solar, wind, biomass, hydro and gas-fired generation. Figure 4.3 shows the installed and projected capacity of embedded generation by fuel type. As the graph shows, the vast majority of the embedded generation is solar. Due to its large share, solar output is treated differently than the other fuel types. The impact of solar generation is generated by using engineering models that use location, cloud cover and temperature to estimate solar production. The remaining embedded generation fuel types' output is produced using average production profiles based on history. The total embedded generation output is then incorporated into the demand forecast. Table 4.2 has a summary of the estimated embedded capacity by fuel type as of June for the history and the forecast period. A more detailed table is included in the 18-Month Outlook Tables.

**Figure 4.3: Projected Embedded Generation Capacity**

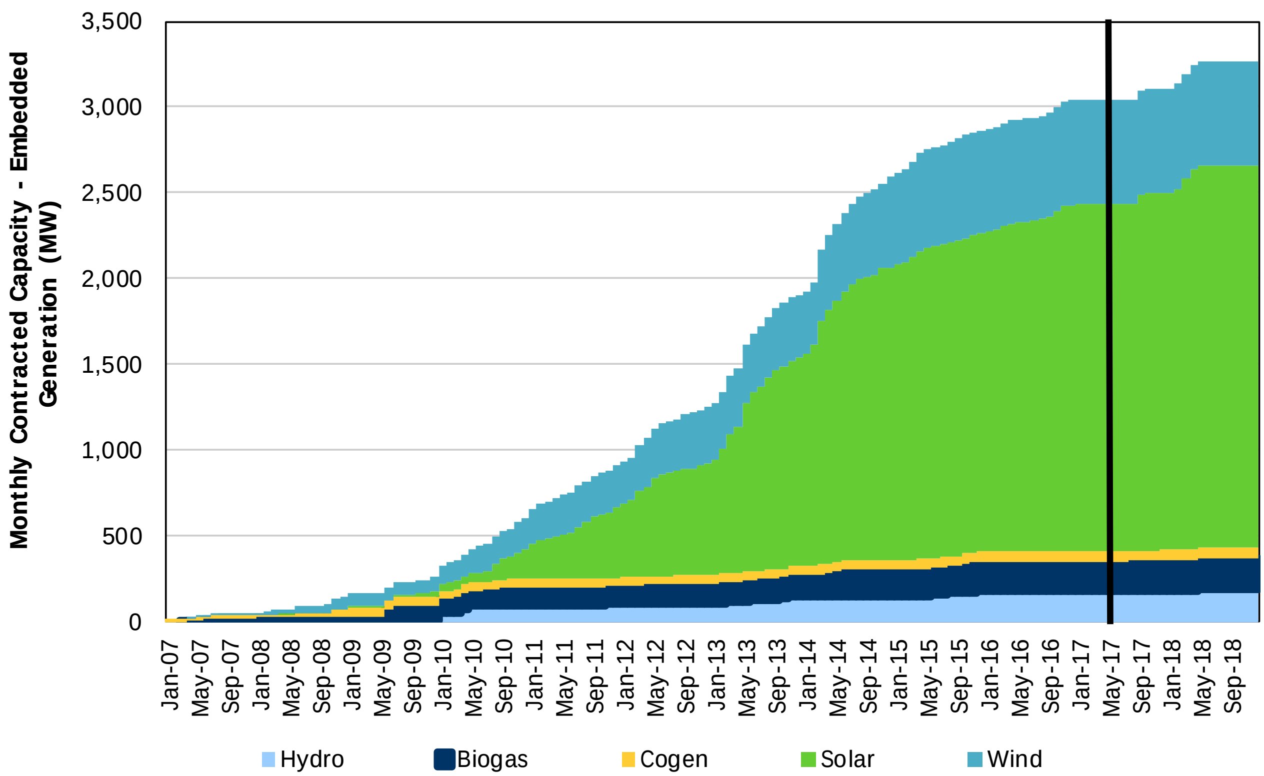



**Table 4.2: Embedded Capacity**

| Month | Estimate of Contracted Embedded Generation Capacity (MW) | | | | | |
|---|---|---|---|---|---|---|
| | Biogas | Cogeneration | Solar | Hydro | Wind | Total |
| Jun-07 | 14 | 18 | 0 | 5 | 7 | 43 |
| Jun-08 | 20 | 25 | 0 | 7 | 38 | 91 |
| Jun-09 | 61 | 49 | 10 | 12 | 74 | 207 |
| Jun-10 | 94 | 49 | 53 | 92 | 160 | 448 |
| Jun-11 | 108 | 49 | 262 | 99 | 241 | 759 |
| Jun-12 | 114 | 49 | 595 | 106 | 298 | 1,162 |
| Jun-13 | 125 | 49 | 1,042 | 123 | 345 | 1,684 |
| Jun-14 | 156 | 55 | 1,567 | 148 | 461 | 2,386 |
| Jun-15 | 161 | 55 | 1,816 | 158 | 575 | 2,765 |
| Jun-16 | 176 | 60 | 1,921 | 176 | 598 | 2,931 |
| Jun-17 | 179 | 60 | 2,017 | 177 | 608 | 3,041 |
| Jun-18 | 182 | 63 | 2,228 | 187 | 608 | 3,269 |

Over the course of the 18-month forecast, the amount of embedded solar installed capacity will range from over 1,900 MW to just over 2,200 MW. The impact of embedded solar on demand will vary over the course of the year and the time of day, due to the amount of sunlight available. Table 4.3 shows the monthly average forecasted capacity factor (%) of embedded solar at the time of the weekday peak hour. Since winter peaks occur after sunset, the average contribution is zero for the winter months. Note that, as discussed in section 3.3, embedded solar is having the impact of pushing summer peaks later in the day. As peaks move later in the day, the result is a reduction in the solar capacity contribution. Therefore solar capacity contribution during peak demand has decreased and will continue to decline. This has not been updated since the last Ontario Demand Outlook.

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

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

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