18 Month Outlook

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

FROM JULY 2016 TO DECEMBER 2017

Connecting Today.
Powering Tomorrow.

Executive Summary

The outlook for the reliability of Ontario's electricity system remains positive for the next 18 months, with adequate generation and transmission to supply Ontario's demand. Long-term forecasts also indicate that Ontario will remain adequately supplied into the foreseeable future.

Over the forecast period, peak demands are expected to remain flat as conservation savings, growing embedded generation output and the Industrial Conservation Initiative (ICI) offset increasing demand from population growth and economic expansion. This is a continuation of the underlying trend since the recession. Although Ontario has a distinct summer peak and winter peak, the summer peak is expected to continue to exceed the winter peak.

Energy demand is expected to show a small increase in 2016 due mostly to the additional day in the leap year. In 2017, economic expansion will help drive a small annual increase in electricity demand. Strong U.S. growth and a lower dollar should provide a boost to Ontario's manufacturing sector throughout the forecast.

The following table summarizes the forecasted seasonal peak demands over the next 18 months.

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2016	22,600	24,740
Winter 2016-17	22,201	23,213
Summer 2017	22,680	24,859

About 1,150 MW of new supply – 650 MW of wind, 300 MW of gas, 100 MW of hydroelectric and 100 MW of solar generation – is expected to be added to the province's transmission grid over the Outlook period. By the end of the period, the amount of grid-connected wind and solar generation is expected to increase to about 4,500 MW and 380 MW, respectively. The embedded wind generation over the same period is expected to increase to about 700 MW. Meanwhile, embedded solar generation is expected to increase to over 2,000 MW.

The Large Renewable Procurement contracts of 455 MW offered on March 10, 2016, have been signed and executed. The IESO initiated a stakeholder and community engagement to invite feedback on the LRP process and understand what improvements can be made prior to the second round of procurement.

As part of its ongoing efforts to help manage variations in generation and demand under a continuously evolving generation mix and demand patterns, the IESO will issue a Request for Information (RFI) for additional regulation service later this month. The RFI will be open to incumbent and new respondents. More information can be found at the Ancillary Services Market webpage at www.ieso.ca/ancillary-services.

The results of a recent operability assessment indicated that there is a system need for enhanced flexibility to balance supply and demand, more regulation and additional grid voltage control. These findings reinforce the need for a portfolio of resources that contributes to the reliability of the grid. The intermediate fleet, gas-fired, oil and hydroelectric generation with storage capability, plays a critical role in complementing the balance of supply by providing response capability, operating reserve and a range of ancillary services.

Conclusions & Observations

The following conclusions and observations are based on the results of this Outlook assessment.

Demand Forecast

- Ontario's grid-supplied peak demand is expected to remain virtually flat over the period of this Outlook. Growth in embedded solar and wind generation capacity and on-going conservation initiatives reduce the need for energy from the bulk power system, while also putting downward pressure on the peak electricity demands. Conservation, time-of-use rates and the ICI also put downward pressure on peak demands, in particular summer peaks. Grid-supplied energy demand is to show a small increase in 2016 and 2017. The increase in 2016 is due to the additional leap year day, while the increased demand from a growing economy will be behind a small growth in demand in 2017.

Resource Adequacy

- Under the **firm scenario**, reserve requirements are expected to be met for the entire duration of this Outlook during normal weather conditions. Under extreme weather conditions, the reserve is below the requirement for 12 weeks, with the highest shortfall of around 1,950 MW. The firm scenario excludes any new generating facilities that haven't reached commercial operation. If the extreme weather materializes, planned generator outages may need to be rescheduled.
- For the **planned scenario**, reserve requirements are expected to be met for the entire duration of this Outlook during normal weather. Under extreme weather conditions with planned resources, the reserve is below requirement for 11 weeks, with the highest shortfall of around 1,950 MW.
- About 1,150 MW of grid-connected generation is expected to be added throughout this Outlook period, which includes 650 MW of wind, 300 MW of gas, 100 MW of hydroelectric and 100 MW of solar generation.

Transmission Adequacy

Ontario's transmission system is expected to be able to reliably supply the demand while experiencing normal contingencies defined by planning criteria under both normal and extreme weather conditions forecast for this Outlook period**.**

- Several local area supply improvement projects are underway and will be placed in service during the timeframe of this Outlook. These projects, shown in Appendix B, will help relieve loadings of existing transmission stations and provide additional supply capacity for future load growth. Additional planning activities through the regional planning process are currently active throughout the province.
- When the level of transfers on the 500 kV system are markedly reduced as a result of medium-to-low load conditions combined with the effect of transactions through the interconnections with our neighbouring utilities, periods of high voltages can occur. While the IESO and Hydro One are currently managing this situation with day-to-day operating procedures, planning work for the installation of new voltage control devices continues.

- Hydro One continues the construction on the Guelph Area Transmission Refurbishment project. The expected completion date is now Q3 2016. This project will improve the transmission capability into the Guelph area by reinforcing the supply into Guelph-Cedar Transformer Station (TS).
- In the Cambridge area, work continues to install in-line switches on the Detweiler to Middleport circuits at Galt Junction. This project, which is scheduled for completion by Q2 2017, will ensure that the IESO's load restoration criteria are met following a contingency on the main supply line. Studies will continue to assess the need for additional measures to address longer-term needs in the area.
- Work to replace aging components at Manby TS in Toronto is on schedule for completion by Q4 2016. This includes bus reinforcement and insulator replacement work.
- A new station, Copeland TS, is still planned to be in service in downtown Toronto in Q4 2016. The new station will facilitate the refurbishment of the facilities at John TS, while also enhancing the load security in the downtown core.

Operability

Conditions for surplus baseload generation (SBG) will continue over the Outlook period. However, it is expected that SBG will continue to be managed effectively through existing market mechanisms, which include inter-tie scheduling, the dispatch of grid-connected renewable resources and nuclear maneuvering or shutdown.

As part of its regular reviews, the IESO is looking carefully at some of the grid's operational needs, which include regulation to balance supply and demand on a second-by-second basis in real time, ramping and load following capability of the Ontario resource fleet and grid voltage control requirements. As a first step, the IESO will soon be conducting an RFI for regulation services that will be open to both incumbent providers and potential new entrants into the regulation service marketplace.

Caution and Disclaimer

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1 Introduction

This Outlook covers the 18-month period from July 2016 to December 2017 and supersedes the last Outlook released on March 22, 2016.

The purpose of the 18-Month Outlook is:

- To advise market participants of the resource and transmission reliability of the Ontario electricity system;
- To assess potentially adverse conditions that might be avoided through adjustment or coordination of maintenance plans for generation and transmission equipment; and
- To report on initiatives being put in place to improve reliability within the 18-month timeframe of this Outlook.

The contents of this Outlook focus on the assessment of resource and transmission adequacy. Additional supporting documents are located on the IESO website at http://www.ieso.ca/Pages/Participate/Reliability-Requirements/Forecasts-&-18-Month-Outlooks.aspx.

This Outlook presents an assessment of resource and transmission adequacy based on the stated assumptions, using the described methodology. Readers may envision other possible scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgment in considering possible future scenarios.

Security and adequacy assessments are published on the IESO website on a daily basis and progressively supersede information presented in this report.

For questions or comments on this Outlook, please contact us at:

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- Tel: 905-403-6900
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- End of Section -

2 Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast is based on actual demand, weather and economic data through to the end of March 2016. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for April and May 2016 has been included in the tables.

2.2 Updates to Resources

The 18-month assessment uses planned generator outages submitted by market participants to the IESO's Integrated Outage Management System (IOMS) as of May 13, 2016.

Regularly, the summer release of the 18-Month Outlook includes annual updates to the capacity contribution from variable resources, solar and wind, and hydroelectric resources for both peak and off-peak assessments. In addition, this Outlook includes data submitted by the market participants using revised Forms 1223 and 1230. The new forms reduce and simplify market participants' information submission requirements and improve the IESO's information management process.[1]

This report period incorporates a number of outages, as identified in Table A8 of the 2016 Q2 Outlook Tables, including the commencement of the nuclear refurbishment program.

The following generators completed the market registration process as of May 13, 2016:

- Grand Valley Wind Farm Phase 3 – 39.7 MW
- Cedar Point Wind Phase 2 – 100 MW
- Armow Wind – 180 MW
- Northland Power Solar Abitibi, Empire, Long Lake and Martin's Meadows – 40 MW

2.3 Updates to Transmission Outlook

The list of transmission projects, planned transmission outages and actual experience with forced transmission outages have been updated from the previous 18-Month Outlook. For this Outlook, transmission outage plans submitted to the IESO's IOMS as of April 22, 2016, were used.

2.4 Updates to Operability Outlook

The Outlook for SBG conditions over the next 18 months is based on generator outage plans submitted by market participants to the IESO's IOMS as of May 13, 2016.

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[1] For more details about the form changes, refer to:

http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Review-of-the-IESOs-Generator-Information-Submittal-Forms-1223-and-1230.aspx

3 Demand Forecast

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period July 2016 to December 2017 and supersedes the previous forecast released in March 2016. Tables of supporting information are contained in the [2016 Q2 Outlook Tables].

Electricity demand is shaped by several factors that have differing impacts. These factors can be grouped into those that increase demand (population growth, additional end-uses and economic expansion), those that reduce demand (conservation and embedded generation) and those that shift demand (time-of-use rates and the ICI). How each of these factors impacts electricity consumption varies by season and time of day. The forecast of demand incorporates these impacts.

Grid-supplied energy demand is forecasted to show a slight increase in 2016 due mostly to the additional day of the leap year, although industrial demand is also up throughout the beginning of 2016. In 2016, the growth in demand from economic expansion and population increases will be offset by the impacts of conservation and embedded generation output. This is due to the fact that conservation reduces the amount of end-use consumption and increased embedded generation output offsets the need for grid-supplied electricity by generating it on the distribution system. For 2017, a stronger U.S. economy combined with a lower dollar will lead to increased manufacturing activity in Ontario, and in turn, higher electricity demand from that sector.

Peak demands are subject to the same forces as energy demand, though the impacts vary. The impacts also vary across from season to season. Summer peaks are significantly impacted by the growth in embedded generation capacity as the vast majority of embedded generation comes from solar-powered facilities, which are producing at high levels during the summer peaks. Winter peaks occur after sunset so there is no solar output during the winter peak periods. Embedded solar is not only reducing the level of the summer peaks, but is also pushing the peaks later in the day. Over the spring and fall, the timing of the peak hour and sunset are moving so the impact of embedded solar will vary. Winter peaks see downward pressure from conservation and lighting efficiency improvements in particular.

With typical weather, the ICI will impact summer peaks for the most part, but extreme cold weather could give rise to ICI impacts during the winter.

Minimum demand levels are similarly impacted by these same forces – primarily economic activity and embedded generation. Since the recession, minimum demand levels have been flat but at a lower level than prior to the recession. Last October saw the lowest post-recession minimum demand level. Increased embedded wind generation further reduces the need for grid-supplied electricity during overnight periods. Since minimums occur in the early morning hours, solar is not active at these times. Over the forecast horizon, minimum demands are expected to remain fairly flat as increased demand through population and economic growth is offset by conservation savings and increased non-solar embedded generation output.

The following tables show the seasonal peaks and annual energy demand over the forecast horizon of the Outlook.

Table 3.1: Forecast Summary

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

Table 3.2: Weekly Energy and Peak Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)	Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
03-Jul-16	22,316	24,044	1,016	2,675					
10-Jul-16	22,600	24,598	814	2,765	09-Apr-17	18,009	18,691	471	2,520
17-Jul-16	22,490	23,756	838	2,656	16-Apr-17	17,296	18,196	496	2,415
24-Jul-16	22,167	24,238	1,035	2,748	23-Apr-17	16,724	16,757	531	2,405
31-Jul-16	22,228	24,325	841	2,735	30-Apr-17	16,708	17,024	721	2,394
07-Aug-16	21,440	24,479	958	2,703	07-May-17	17,476	20,309	849	2,357
14-Aug-16	21,214	24,147	985	2,677	14-May-17	17,657	19,713	845	2,375
21-Aug-16	21,244	23,857	1,362	2,706	21-May-17	18,555	21,837	1,175	2,398
28-Aug-16	20,239	22,722	1,413	2,570	28-May-17	18,613	21,955	1,330	2,339
04-Sep-16	18,766	22,292	1,370	2,472	04-Jun-17	19,170	21,603	1,292	2,438
11-Sep-16	18,302	20,848	680	2,438	11-Jun-17	19,844	23,981	1,055	2,570
18-Sep-16	17,969	20,164	781	2,462	18-Jun-17	20,919	24,092	835	2,584
25-Sep-16	17,079	18,415	420	2,385	25-Jun-17	22,269	24,304	754	2,651
02-Oct-16	17,252	17,472	554	2,439	02-Jul-17	22,219	23,869	1,016	2,639
09-Oct-16	17,143	17,557	786	2,463	09-Jul-17	22,680	24,716	814	2,739
16-Oct-16	17,645	18,174	507	2,413	16-Jul-17	22,339	23,764	838	2,777
23-Oct-16	17,735	18,374	392	2,498	23-Jul-17	22,132	23,880	1,035	2,673
30-Oct-16	18,166	18,821	318	2,526	30-Jul-17	22,187	24,648	841	2,758
06-Nov-16	18,442	19,179	416	2,593	06-Aug-17	22,413	24,394	958	2,773
13-Nov-16	19,145	20,060	601	2,618	13-Aug-17	22,005	24,621	985	2,728
20-Nov-16	19,753	20,639	342	2,688	20-Aug-17	21,390	24,350	1,362	2,700
27-Nov-16	20,276	21,414	607	2,743	27-Aug-17	21,423	23,434	1,413	2,708
04-Dec-16	20,406	21,787	409	2,773	03-Sep-17	20,623	22,915	1,370	2,590
11-Dec-16	20,906	21,849	555	2,815	10-Sep-17	18,934	22,255	680	2,440
18-Dec-16	20,913	21,895	690	2,816	17-Sep-17	19,418	21,075	781	2,502
25-Dec-16	20,514	22,498	362	2,875	24-Sep-17	18,141	20,089	420	2,474
01-Jan-17	20,413	21,451	528	2,690	01-Oct-17	17,350	18,599	554	2,409
08-Jan-17	21,518	22,258	570	2,850	08-Oct-17	17,531	17,458	786	2,453
15-Jan-17	22,201	23,190	547	2,932	15-Oct-17	17,477	17,290	507	2,435
22-Jan-17	21,775	22,182	483	2,921	22-Oct-17	17,923	18,226	392	2,476
29-Jan-17	21,549	22,309	404	2,925	29-Oct-17	18,022	18,438	318	2,517
05-Feb-17	21,175	22,247	734	2,931	05-Nov-17	18,282	18,795	416	2,519
12-Feb-17	20,694	21,984	635	2,874	12-Nov-17	19,321	19,713	601	2,623
19-Feb-17	20,191	21,738	581	2,823	19-Nov-17	19,659	20,254	342	2,647
26-Feb-17	20,096	21,740	501	2,773	26-Nov-17	20,088	20,742	607	2,718
05-Mar-17	20,265	21,337	531	2,790	03-Dec-17	20,545	21,467	409	2,767
12-Mar-17	20,018	20,695	649	2,756	10-Dec-17	20,740	21,677	555	2,790
19-Mar-17	18,933	19,744	611	2,674	17-Dec-17	21,036	21,902	690	2,831
26-Mar-17	18,461	19,126	569	2,586	24-Dec-17	20,885	21,856	362	2,802
02-Apr-17	18,371	19,399	567	2,563	31-Dec-17	20,569	21,719	528	2,702

3.1 Actual Weather and Demand

Since the last forecast, the actual demand and weather data for March, April and May have been recorded.

March

- March was milder than normal, though the peak day temperature was quite close to normal peak weather. In terms of average temperature, it was the fifth mildest in the past 30 years but was 13th in terms of peak day temperature.
- The March electricity demand peak occurred on the coldest day of the month, March 1. Peak demand was 20,063 MW, which is fairly consistent with March peaks since 2009.

After adjusting for the weather, the peak was marginally higher at 20,153 MW. This is a slight increase over the previous March.

- Energy demand for the month was 11.3 TWh (11.5 TWh weather corrected). Both of these values are low points for March demand, falling lower than the values of the past couple of years.
- The minimum demand for the month was 11,717 MW, which is fairly consistent with March values since the 2009 recession.
- Wholesale customers' consumption for the month was virtually flat compared to the previous March.
- Embedded generation for the month was 536 GWh, which is an increase of 6.5% over the previous March, with the increase split evenly between solar and wind output.

April

- The weather for April was colder than normal. Monthly energy demand was 10.4 TWh (both actual and weather corrected). The weather-corrected values are consistent with the trend since the recession.
- The peak electricity demand occurred on Tuesday, April 5, which was the fifth coldest day of the month. Though not particularly cold, it did follow the two coldest days of the month. The peak was 17,821 MW and, since the weather was colder than normal, the weather-corrected peak was lower at 17,474 MW.
- Minimum demand for the month was 14,458 MW, which occurred at 4 a.m. on a Sunday.
- Wholesale customers' consumption continued to build on the strength seen since the beginning of 2016. Their loads increased 2.2 percent compared to the previous April.
- Embedded generation for the month was 669 GWh, an increase of 0.8 percent over the previous April.

May

- May started colder than normal, but ended being warmer than normal. Overall the month was warmer than normal. The actual peak for May was 19,885 MW, occurring on Monday, May 30. It was only the 6th warmest day of the month, but followed a weekend with the two hottest days of the month. The weather-corrected value was a slightly lower 19,705 MW. The weather corrected value was the highest since May 2012.
- The impacts of conservation and embedded generation mean that the energy demand for the month has been fairly flat since the recession, but trending downward. Actual demand was 10.5 TWh, and weather corrected energy was a slightly lower 10.2 TWH. Both are historical lows for May.
- Minimum demand of 10,804 MW occurred on Sunday, May 8 at 4 a.m. This is a slight increase from last year and marginally better than the levels experienced during the recession.

- Embedded generation for the month was 676 GWh, which is an increase of 26 percent over the previous May.
- After four months of growth, wholesale customers' load dropped by 0.9 percent compared to the previous May.

2016 Spring Actuals

Overall, energy demand for the spring months of March through May was down 2.5 percent compared with the same three months one year prior. Some of this was due to the mild March, but even after adjusting for weather, energy demand saw a 1.0% decline.

Over the spring, wholesale customers' consumption seems to gaining a bit of traction as it grew by 0.4 percent compared to the previous spring. Once again, the growth has not been consistent but is an encouraging sign that the low dollar and strong U.S. growth could be impacting the industrial sector. Wholesale load had seen year over year declines in 11 of the 12 months in 2015, so growth over the winter and spring represents a reversal. Over the past year, Ontario's manufacturing employment has been up in 9 of the 12 months, the strongest growth since the fall of 2012. These are positive signs heading into the summer.

The 2016 Q2 Outlook Tables contain several tables with historical data. They are:

- Table 3.3.1 Weekly Weather and Demand History Since Market Opening
- Table 3.3.2 Monthly Weather and Demand History Since Market Opening
- Table 3.3.3 Monthly Demand Data by Market Participant Role.

3.2 Forecast Drivers

3.2.1 Economic Outlook

Currently, the Ontario economy has two significant factors in its favour: strong U.S. growth and a low Canadian dollar. The growth translates into demand for goods and services, and the more favourable exchange rate means Ontario is more cost competitive. Data since the start of 2016 points to an upturn in Ontario's manufacturing sector.

Despite a number of downside risks – slower Chinese growth, debt issues and low commodity prices – the economic outlook remains quite positive for the province over the forecast horizon.

Wholesale customers' electricity consumption had been weak since the fall of 2014. However, their load has grown by 1.0 percent over the first five months of the year.

Table 3.3.4 of the 2016 Q2 Outlook Tables presents the economic assumptions for the demand forecast.

3.2.2 Weather Scenarios

The IESO uses weather scenarios to produce demand forecasts. These scenarios include normal and extreme weather, along with a measure of uncertainty in demand due to weather volatility. This measure is called Load Forecast Uncertainty (LFU).

Table 3.3.5 of the 2016 Q2 Outlook Tables presents the weekly weather data for the forecast period.

3.2.3 Pricing, Conservation and Embedded Generation

The demand forecast accounts for pricing, conservation and embedded generation impacts. These impacts are grouped together and assessed as load modifiers as they act to reduce the grid-supplied demand.

Pricing incentives cause both the reduction in demand and the shifting of demand away from peak periods. Pricing includes TOU rates and the ICI. TOU rates incent consumers to reduce loads during peak demand periods by either shifting to off-peak periods or reducing consumption altogether. TOU can factor into all weekdays throughout the year, and the size of the impact will be determined by the pricing structure. The ICI impacts the five to 10 highest peak days of the program year. Prior to 2014, the impact of ICI was just under 900 MW on the five highest peaks. In 2014, the program was expanded to include loads with a peak demand of 3 - 5 MW. This has led to an increase in the ICI impacts for the period May 2015 to April 2016. Estimates indicate that ICI impacts over the five highest peaks increased up to 1,075 MW, up almost 100 MW from the previous year. Part of the increase might have come from the fact that most of the peaks were grouped and therefore easier to anticipate.

Output from embedded generators directly offsets the need for the same quantity of grid-supplied electricity. Embedded generation capacity is expected to grow over the forecast horizon and the impact of increased embedded output is factored into the demand forecast.

Conservation also reduces the need for grid-supplied electricity by reducing end-use consumption. Conservation will continue to grow throughout the forecast period and the demand forecast is decremented for those impacts.

The demand measures, which are dispatchable loads, Peaksaver Plus, Capacity-Based Demand Response (CBDR) and resources secured through the Demand Response (DR) Auction are treated as resources in the assessment and are further discussed in section 4.1.3. In terms of the demand forecast, the actual impacts of these programs are added back to the demand and the forecast is based on demand prior to the effects of these programs.

- End of Section -

4 Resource Adequacy Assessment

This section provides an assessment of the adequacy of resources to meet the forecast demand. When reserves are below required levels, with potentially adverse effects on the reliability of the grid, the IESO will reject outage requests based on their order of precedence. Conversely, an opportunity exists for additional outages when reserves are above required levels.

The existing installed generation capacity is summarized in Table 4.1. This includes capacity from new projects that have completed commissioning and the IESO's market entry process. The forecast capability at the Outlook peak is based on the firm resource scenario, which includes resources currently under commercial operation, and takes into account deratings, planned outages and allowance for capability levels below rated installed capacity.

Table 4.1: Existing Generation Capacity as of May 13, 2016

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Outlook Peak (MW)	Number of Stations	Change in Installed Capacity (MW)	Change in Stations
Nuclear	12,978	11,031	5	0	0
Hydroelectric	8,432	5,855	71	0	0
Gas/Oil	9,942	8,530	30	0	0
Wind	3,823	474	33	320	3
Biofuel	495	459	9	0	0
Solar	280	28	6	40	2
Total	**35,951**	**26,378**	**154**	**360**	**5**

4.1 Assessment Assumptions

4.1.1 Committed and Contracted Generation Resources

All generation projects that are scheduled to come into service, be upgraded or shut down within the Outlook period are summarized in Table 4.2. This includes committed generation projects in the IESO's Connection Assessment and Approval process (CAA), those that are under construction, as well as projects contracted by the IESO. Details regarding the IESO's CAA process and the status of these projects can be found on the IESO's website at http://www.ieso.ca/Pages/Participate/Connection-Assessments/default.aspx under Application Status.

The estimated effective date in Table 4.2 indicates the date on which additional capacity is assumed to be available to meet Ontario demand or when existing capacity will be shut down. This data is current as of May 13, 2016. For projects that are under contract, the estimated effective date is based on the best information available to the IESO. If a project is delayed, the estimated effective date will be the best estimate of the commercial operation date for the project.

Table 4.2: Committed and Contracted Generation Resources

Project Name	Also Known As	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered	
						Firm (MW)	Planned (MW)
Bow Lake Phase 1		Northeast	Wind		Commercial Operation	20	20
Bow Lake Phase 2b		Northeast	Wind		Commercial Operation	40	40
Upper White River Generating Station		Northwest	Water	2016-Q2	Commissioning		9
Lower White River Generating Station		Northwest	Water	2016-Q2	Commissioning		10
Grand Bend Wind Farm	Zurich	Southwest	Wind	2016-Q3	Commissioning		99
Harmon Unit 2 Runner Upgrade		Northeast	Water	2016-Q3	Under Development		10
Beck 1 Unit Overhaul		Niagara	Water	2016-Q4	Under Development		12
Green Electron Power		West	Gas	2016-Q4	Under Development		298
Niagara Region Wind Farm		Southwest	Wind	2016-Q4	Under Development		230
South Gate Solar		Southwest	Solar	2016-Q4	Under Development		50
Windsor Solar		West	Solar	2016-Q4	Under Development		50
Namewaminikan Hydro		Northwest	Water	2016-Q4	Under Development		10
Kingston Cogen		East	Gas	2017-Q1	Expiring Contract	-140	
Amherst Island Wind		East	Wind	2017-Q1	Under Development		75
Harmon Unit 1 Runner Upgrade		Northeast	Water	2017-Q3	Under Development		10
Peter Sutherland Senior Generating Station		Northeast	Water	2017-Q3	Under Development		28
Belle River Wind		West	Wind	2017-Q3	Under Development		100
North Kent Wind 1		West	Wind	2017-Q4	Under Development		100
Total						**-80**	**1152**

Notes on Table 4.2:

1. The total may not add up due to rounding and does not include in-service facilities.
2. Project status provides an indication of the project progress. The milestones used are:
    a. Under Development – includes projects in approvals and permitting stages (e.g., environmental assessment, municipal approvals, IESO connection assessment approvals, etc.) and projects under construction.
    b. Commissioning – the project is undergoing commissioning tests with the IESO.
    c. Commercial Operation – the project has achieved commercial operation under the contract criteria but has not met all the market registration requirements of the IESO.
    d. Expiring Contract – Non-Utility Generators (NUGs) whose contracts expire during the Outlook period are included in both scenarios only up to their contract expiry date. If the NUGs continue to provide forecast data, they are included in the planned scenario for the rest of the outlook period, too.

4.1.2 Generation Capability Assumptions

Hydroelectric

The hydroelectric capability for the duration of this Outlook is based on median historical values (including energy and operating reserve) during weekday peak demand hours. Table 4.3 shows the historical hydroelectric median values calculated with the data from May 2002 to March 2016. These values are updated annually to coincide with the release of the summer 18-Month Outlook.

Table 4.3: Monthly Historical Hydroelectric Median Values

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical Hydroelectric Median Values (MW)	6,069	6,003	5,869	5,792	5,818	5,658	5,671	5,382	5,086	5,416	5,728	6,122

Thermal Generators

Thermal generators' capacity and energy contributions, planned outages, expected forced outage rates and seasonal deratings are based on market participant submissions or calculated by the IESO based on actual experience. Starting with this Outlook, thermal generators that are sensitive to ambient temperatures have their monthly capability calculated by the IESO based on the information submitted by market participants and the representative monthly temperatures, as explained in the [Methodology to Perform Long Term Assessments] document. Data submitted by the market participants from revised Forms 1223 and 1230 were utilized. The new forms reduce and simplify market participants' information submission requirements, and improve the quality of information and IESO's information management process.[2]

Wind

For wind generation, the monthly Wind Capacity Contribution (WCC) values are used at the time of weekday peak. The specifics on wind contribution methodology can be found in the Methodology to Perform Long-Term Assessments. Table 4.4 shows the monthly WCC values. These values are updated annually to coincide with the release of the summer Outlook. For this Outlook, actual historic data up to March 31, 2016, was used; simulated wind data is no longer necessary, as 10 years of actual data is available.

Table 4.4: Monthly Wind Capacity Contribution Values

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
WCC (% of Installed Capacity)	37.8%	37.8%	33.3%	33.2%	21.2%	12.2%	12.2%	12.2%	16.2%	31.2%	34.2%	37.8%

Solar

For solar generation, the monthly Solar Capacity Contribution (SCC) values are used at the time of weekday peak. The specifics on solar contribution methodology can be found in the Methodology to Perform Long-Term Assessments. Table 4.5 shows the monthly SCC values that are updated annually to coincide with the release of the summer Outlook.

The grid demand profile has been changing, with summer peaks being pushed later in the day. While the contribution of the embedded solar generation displaces load during the daylight hours reducing demand at the grid level, solar power output at the new peak hours is considerably lower. Therefore, the SCC values at peak dropped significantly and are expected to stay at these levels over the peak period in the foreseeable future. However, solar generation continues to contribute to meeting energy needs during daylight hours.

Table 4.5: Monthly Solar Capacity Contribution Values

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCC (% of Installed Capacity)	0.0%	0.0%	0.0%	1.3%	2.9%	10.1%	10.1%	10.1%	8.6%	0.0%	0.0%	0.0%

[2] For more details about the form changes, refer to:

http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Review-of-the-IESOs-Generator-Information-Submittal-Forms-1223-and-1230.aspx

4.1.3 Demand Measures

Both demand measures and load modifiers can impact demand but they differ in how they are treated within the Outlook. Demand measures, i.e., dispatchable loads, Peaksaver Plus, DR and CBDR, are not incorporated into the demand forecast and are instead treated as resources. Load modifiers are incorporated into the demand forecast, as explained in section 3.2.3.

Demand measures are treated as generation resources and are therefore included in the supply mix. Demand measures are added back into the history when forecasting demand.

The first DR auction, held in December 2015, procured 391.5 MW of DR capacity for the 2016 summer beginning May 1, 2016, period and 403.7 MW for the 2016-17 winter period beginning November 1, 2016. The DR capacity acquired through the DR auction is reflected in the Outlook. The next DR auction will be held in December 2016 with the first commitment period beginning May 1, 2017.

In addition, approximately 70 MW of demand is participating in the DR Pilot Program since May 2016 for a two-year term. These pilot projects will be used to help identify opportunities to enhance participation of DR in meeting Ontario's existing system needs, assess their ability to follow changes in electricity consumption and help balance supply and demand.

4.1.4 Firm Transactions

As part of the seasonal firm capacity sharing agreement between Ontario and Quebec, Ontario will make available 500 MW of capacity to Quebec for the winter of 2016-17, similar with the last winter. This commitment has been reflected in the adequacy assessments for the period covered under this Outlook. This Outlook period also includes the first month of the 2017-18 winter, and although the 500 MW of exports has yet to be confirmed, it is included in our assessment.

The IESO has the option to call on up to 500 MW of capacity from Quebec for summer seasons, at least one year in advance of the delivery period. No request was made for summer 2016 or summer 2017.

4.1.5 Summary of Scenario Assumptions

To assess future resource adequacy, the IESO must make assumptions on the amount of available resources. The Outlook considers two scenarios: a **firm scenario** and a **planned scenario** as compared in Table 4.6.

Table 4.6: Summary of Scenario Assumptions for Resources

	Planned Scenario	Firm Scenario
Total Existing Installed Resource Capacity (MW)	35,951	
New Generation and Capacity Changes (MW)	1,152	-80

The starting point of both scenarios is the existing installed resources shown in Table 4.1. The **planned scenario** assumes that all resources scheduled to come into service are available over the assessment period. The **firm scenario** only assumes resources that have reached commercial operation. The generator planned shutdowns or retirements that have high certainty of occurring in the future are also considered for both scenarios. NUGs whose contracts expire during the Outlook period are included in both scenarios only up to their contract expiry date. If the NUGs continue to provide forecast data, they are included in the planned scenario for the rest of the outlook period, too. The **firm** and **planned** scenarios also differ in their assumptions regarding the amount of demand measures. The **firm scenario** considers DR programs from existing participants only, while the **planned scenario** considers DR programs from future participants too. Both scenarios recognize that resources are not available during times for which the generator has submitted planned outages.

Table 4.7 shows a snapshot of the forecast available resources, under the two scenarios, at the time of the summer and winter peak demands during the Outlook.

Table 4.7: Summary of Available Resources

Notes	Description	Summer Peak 2016		Winter Peak 2017		Summer Peak 2017	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,011	36,030	36,011	36,789	36,011	36,864
2	Total Reductions in Resources (MW)	10,244	10,140	8,059	8,213	9,939	10,376
3	Demand Measures (MW)	674	674	693	693	674	674
4	Firm Imports (+) / Exports (-) (MW)	0	0	-500	-500	0	0
5	Available Resources (MW)	26,441	26,564	28,145	28,770	26,746	27,163

Notes on Table 4.7:

1. Installed Resources: the total generation capacity assumed to be installed at the time of the summer and winter peaks.
2. Total Reductions in Resources: the sum of deratings, planned outages, limitations due to transmission constraints and allowance for capability levels below rated installed capacity.
3. Demand Measures: the amount of demand expected to be available for reduction at the time of peak.
4. Firm Imports / Exports: the amount of expected firm imports and exports at the time of summer and winter peaks.
5. Available Resources: Installed Resources (line 1) minus Total Reductions in Resources (line 2) plus Demand Measures (line 3) and Firm Imports / Exports (line 4).

4.2 Capacity Adequacy Assessment

The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages. The planned outages occurring during this Outlook period have been assessed as of May 13, 2016.

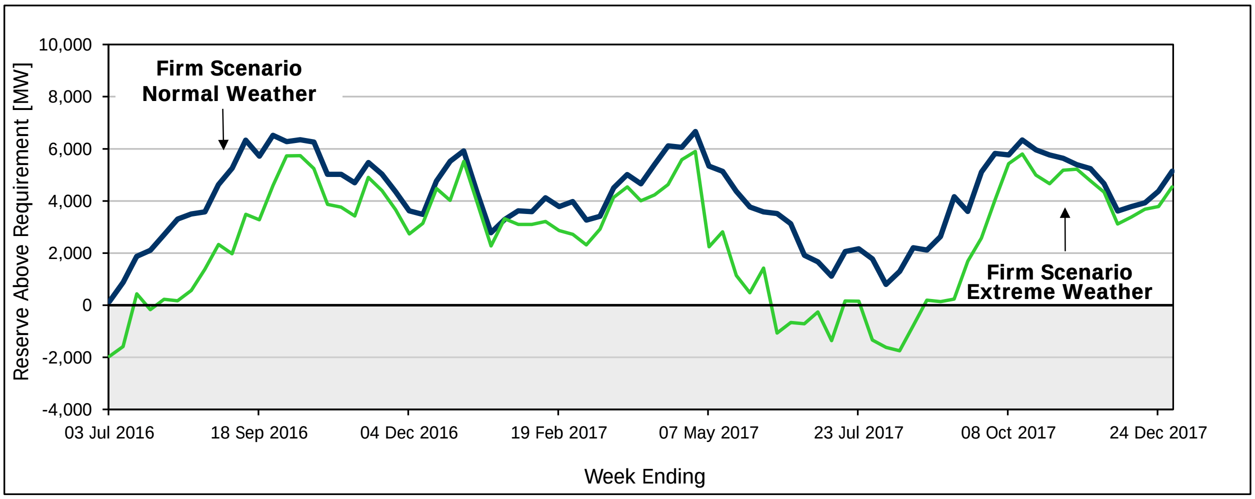
4.2.1 Firm Scenario with Normal and Extreme Weather

The **firm scenario** incorporates all existing capacity plus capacity that reached commercial operation as on May 13, 2016. Roughly 60 MW of wind capacity are at commercial operation status.

Figure 4.1 shows the Reserve above Requirement (RAR) levels, which represent the difference between Available Resources and Required Resources. The Required Resources equals the Demand plus Required Reserve. As can be seen, the reserve requirement in the **firm scenario** under normal weather conditions is being met throughout the entire Outlook period. During extreme weather conditions, the reserve is lower than the requirement for a total of 12 weeks during the 18-month Outlook timeframe. This shortfall is largely attributed to the planned generator outages scheduled during those weeks.

Should the extreme weather conditions occur, planned outages may need to be rescheduled.

Figure 4.1: Normal vs. Extreme Weather: Firm Scenario RAR

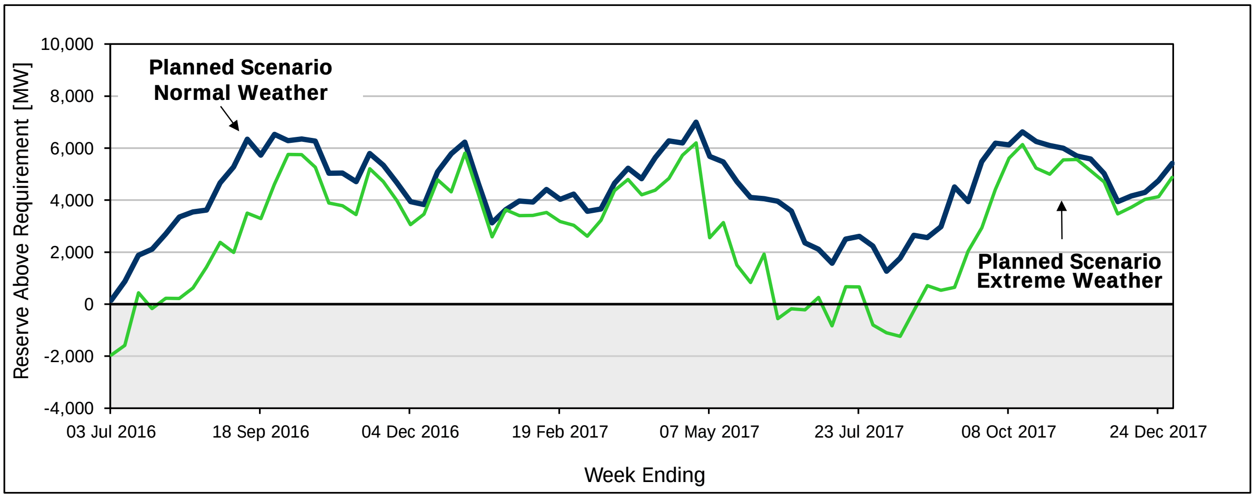


4.2.2 Planned Scenario with Normal and Extreme Weather

The **planned scenario** incorporates all existing capacity plus all capacity coming in service. Roughly 1,150 MW of generation capacity is expected to connect to Ontario's grid over this Outlook period.

Figure 4.2 shows the RAR levels under the **planned scenario**. As observed, the reserve requirement is being met throughout the Outlook period under normal weather conditions. The reserve is lower than the requirement for 11 weeks during the 18-month Outlook timeframe under extreme weather conditions. This shortfall is largely attributed to the planned outages scheduled for those weeks.

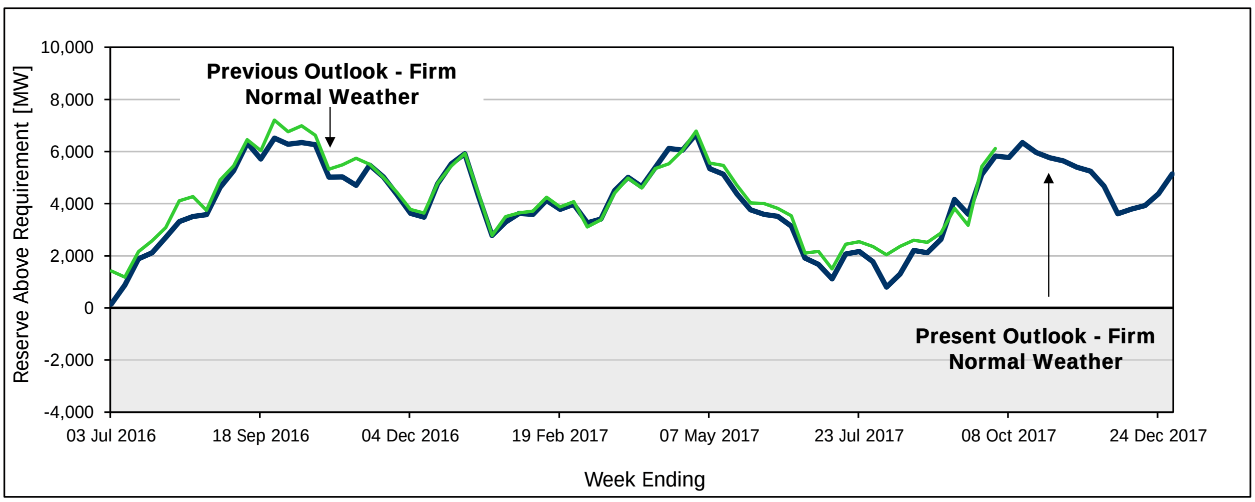
Figure 4.2: Normal vs. Extreme Weather: Planned Scenario RAR



4.2.3 Comparison of the Current and Previous Weekly Adequacy Assessments for the Firm Normal Weather Scenario

Figure 4.3 provides a comparison between the forecast RAR values in the present Outlook and the forecast RAR values in the previous Outlook published on March 22, 2016. The difference is mainly due to the changes to outages and changes in the demand forecast.

Figure 4.3: Present Outlook vs. Previous Outlook: Firm Scenario - Normal Weather RAR



Resource adequacy assumptions and risks are discussed in detail in the [Methodology to Perform Long-Term Assessments].

4.3 Energy Adequacy Assessment

This section provides an assessment of energy adequacy, the purpose of which is to determine whether Ontario has sufficient supply to meet its forecast energy demands and to highlight any potential concerns associated with energy adequacy within the period covered under this 18-Month Outlook. At the same time, the assessment estimates the aggregate production by each resource category to meet the projected demand based on assumed resource availability.

4.3.1 Summary of Energy Adequacy Assumptions

The Energy Adequacy Assessment (EAA) is performed using the same set of assumptions pertaining to resources expected to be available over the next 18 months as in the capacity assessments. Refer to Table 4.1 for the summary of 'Existing Generation Capacity' and Table 4.2 for the list of 'Committed and Contracted Generation Resources' for this information. The monthly forecast of energy production capability, based on the energy modelling results, is included in the Table A7 of the 2016 Q2 Outlook Tables.

For the EAA, only the **planned scenario** as per Table 4.6 with normal weather demand is considered. The key assumptions specific to this assessment are described in the IESO document titled Methodology to Perform Long-Term Assessments.

4.3.2 Results – Planned Scenario with Normal Weather

Table 4.8 summarizes key energy statistics over the 18-month period for the planned scenario with normal weather demand for Ontario as a whole, and provides a breakdown by each transmission zone.

The results indicate that supply is expected to be adequate over the 18-month timeframe of this Outlook, with no occurrences of unserved energy.

Table 4.8: Planned Scenario - Normal Weather: Summary of Zonal Energy

Zone	18 -Month Energy Demand		18-Month Energy Production		Net Inter-Zonal Energy Transfer	Zonal Energy Demand on Peak Day of 18-Month Period	Available Energy on Peak Day of 18-Month Period
	TWh	Average MW	TWh	Average MW	TWh	GWh	GWh
Ontario	**206.3**	**15,654.0**	**206.3**	**15,654.0**	**0.0**	**453.9**	**607.5**
Bruce	0.9	71.0	68.2	5,177.0	67.3	1.2	155.2
East	12.9	976.0	14.6	1,111.0	1.7	25.4	81.6
Essa	11.9	903.0	3.2	240.0	-8.7	24.8	12.9
Niagara	6.2	469.0	19.7	1,492.0	13.5	14.1	42.2
Northeast	15.9	1,209.0	15.3	1,158.0	-0.6	25.8	34.2
Northwest	6.0	459.0	5.7	433.0	-0.3	9.9	19.3
Ottawa	12.7	961.0	0.5	37.0	-12.2	26.6	2.1
Southwest	43.1	3,275.0	5.4	413.0	-37.7	95.3	22.7
Toronto	77.9	5,909.0	66.8	5,067.0	-11.1	183.1	163.9
West	20.4	1,548.0	8.6	652.0	-11.8	47.7	73.4

Figure 4.4 shows the percentage production to supply Ontario energy demand by fuel type for the entire duration of the outlook, while Figure 4.5 shows the production by fuel type for each month of the 18-month period. Exports out of Ontario and imports into Ontario are not considered in this assessment. Table 4.9 summarizes these simulated production results by fuel type, for each year.

Figure 4.4: Production by Fuel Type – July 1, 2016, to Dec. 31, 2017

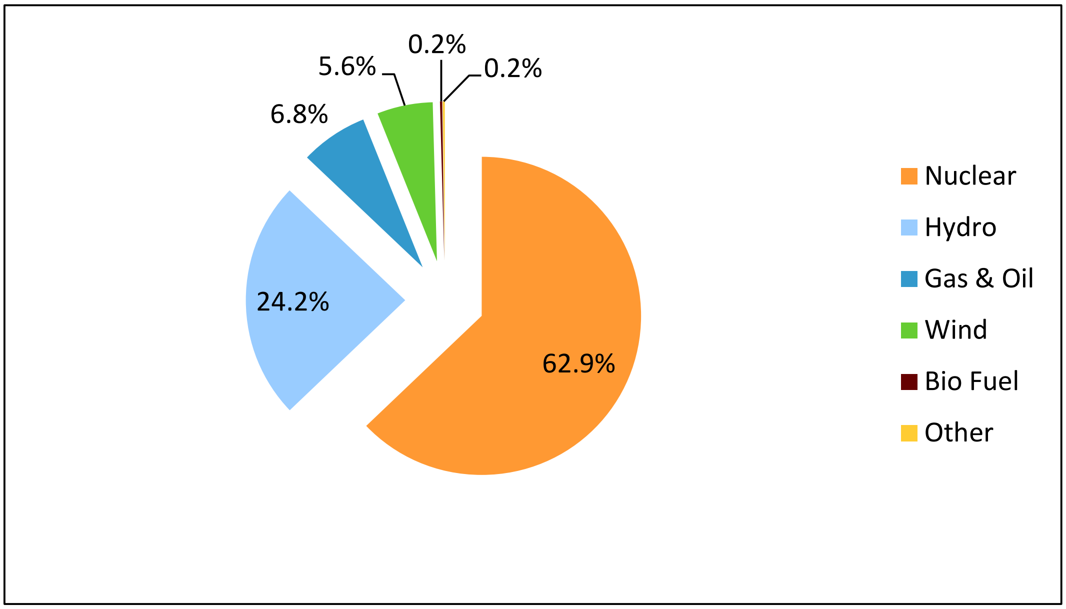


Figure 4.5 Monthly Production by Fuel Type – July 1, 2016, to Dec. 31, 2017

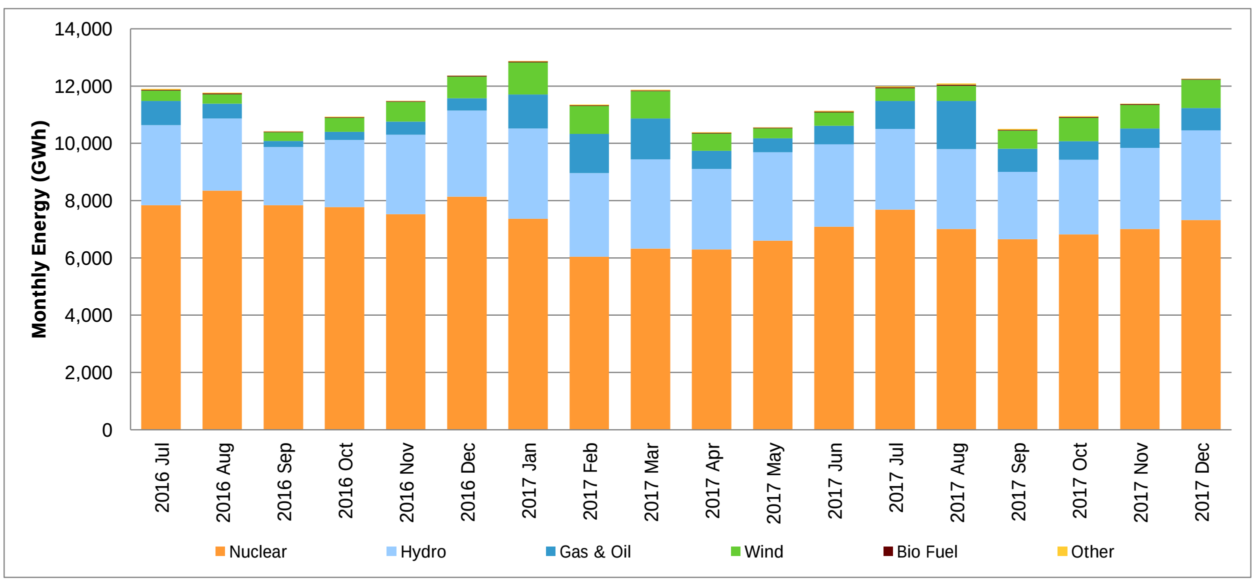


Table 4.9: Planned Scenario - Normal Weather: Ontario Energy Production by Fuel Type

Fuel Type (Grid Connected)	2016 (Apr 1 – Dec 31) (GWh)	2017 (Jan 1 – Sep 30) (GWh)	Total (GWh)
Nuclear	47,466	82,221	129,687
Hydro	15,466	34,500	49,965
Gas & Oil	2,763	11,320	14,083
Wind	2,922	8,708	11,631
Biofuel	153	316	469
Other (Solar & DR)	115	304	419
Total	**68,885**	**137,369**	**206,254**

4.3.3 Findings and Conclusions

The EAA results indicate that Ontario is expected to have sufficient supply to meet its energy forecast during the 18-Month Outlook period for the planned scenario with normal weather demand.

- End of Section -

5 Transmission Reliability Assessment

For the purpose of this report, transmitters provide information on the transmission projects that are planned for completion within the 18-month period. Construction of several transmission reinforcements is expected to be completed during this Outlook period. Major transmission and load supply projects planned to be in service are shown in Appendix B. Projects that are already in service or whose completion is planned beyond the period of this Outlook are not shown. The list includes only the transmission projects that represent major modifications or are considered to significantly improve system reliability. Minor transmission equipment replacements or refurbishments are not shown.

Some areas have experienced load growth to warrant additional investments in new load supply stations and reinforcements of local area transmission. Several local area supply improvement projects are underway and will be placed in service during the timeframe of this Outlook. These projects help relieve loadings on existing transmission infrastructure and provide additional supply capacity for future load growth.

5.1 Transmission Outages

The IESO's assessment of the transmission outage plans is shown in Appendix C, Tables C1 to C10. The methodology used to assess the transmission outage plans is described in the IESO document titled Methodology to Perform Long-Term Assessments. This Outlook contains transmission outage plans submitted to the IESO as of May 3, 2016.

5.2 Transmission System Adequacy

The IESO assesses transmission adequacy using the methodology on the basis of conformance to established criteria, planned system enhancements and known transmission outages. Zonal assessments are presented in the following sections. Overall, the Ontario transmission system is expected to supply the demand under the normal and extreme weather conditions forecast for the Outlook period.

The existing transmission infrastructure in some areas in the province, as described below, have been identified as currently having or anticipated to have some limitations to supply the local needs. Additional planning activities are currently active throughout the province through regional planning. For links to completed plans and information on active plans, please visit the IESO regional planning webpage: http://www.ieso.ca/Pages/Participate/Regional-Planning/.

5.2.1 Toronto and Surrounding Area

The load supply capability to the GTA is expected to be adequate to meet the forecast demand through to the end of this 18-month period.

The expected completion date to replace aging components at Manby TS remains Q4 2016. This includes bus reinforcement and insulator replacement work. The expected completion date for the load rejection scheme that will help alleviate any overloads following the loss of any two Manby transformers is now Q2 2018.

In central Toronto, the expected completion date for Copeland TS remains Q4 2016. The new station will allow some load to be transferred from John TS. This will help meet the short- and mid-term need for additional supply capacity in the area and will also enable the refurbishment of the facilities at John TS.

High voltages in southern Ontario continue to present operational challenges during periods when the level of transfers on the 500 kV system are markedly reduced as a result of medium-to-low load conditions, combined with the effect of transactions via the interconnections with our neighbouring utilities. Temporary removal from service of at least one of the 500 kV circuits between Lennox TS and Bowmanville Switching Station (SS) continues to be required during those periods. The situation has become especially acute during those periods when the shunt reactors at Lennox TS have been unavailable. While the IESO and Hydro One are currently managing this situation with day-to-day operating procedures, planning work to identify longer-term mitigation measures, including the installation of voltage control devices, continues.

To increase the load-meeting capability of the two 230 kV circuits between Claireville TS and Minden TS and enable the proposed Vaughan TS No. 4 to be connected, Hydro One is planning to install two 230 kV in-line breakers at Holland TS, together with a load rejection scheme. These facilities are expected to be in service by Q4 2017. Until these facilities become available, operational measures will be required to avoid possible overloading of these circuits during peak load periods.

Transmission transfer capability in Toronto and surrounding area is expected to be sufficient for the purpose of supplying load, with sufficient margin to allow for planned outages.

5.2.2 Bruce and Southwest Zones

In the Guelph area, Hydro One continues construction on the Guelph Area Transmission Refurbishment project to improve the transmission capability into the Guelph area by reinforcing the supply into Guelph-Cedar TS. The expected completion date is now Q3 2016. As part of this project, circuit switchers are to be installed at Guelph North Junction that will enable the 230 kV system between Detweiler TS and Orangeville TS to be sectionalized. These devices will reduce the restoration times for the loads in the Waterloo, Guelph and Fergus areas following a supply interruption.

Work to install in-line switches on the Detweiler to Middleport circuits at Galt Junction continues. This work, which is scheduled to be completed by Q2 2017, will improve the load restoration capability to customers in the Cambridge area following outages on transmission circuits. It will also accommodate the development of the Cambridge No. 2 TS on the 115 kV system between Preston TS and Detweiler TS to meet load growth in the area. Planning work to address the longer-term supply needs of the area beyond 2016 continues.

Hydro One is continuing work to replace the aging infrastructure at the Bruce 230 kV switchyard, which is scheduled to be completed by Q2 2019. While this work is being implemented, careful coordination of the transmission and generation outages will be needed.

Hydro One is also continuing work on a new Bruce Remedial Action Scheme (RAS), which continues to be scheduled for completion by December 2016. This new RAS will replace the existing special protection system while having increased functionality to detect and operate for a greater number of contingencies.

The transmission transfer capability in the Southwest zone and its vicinity is expected to be sufficient to supply the load in this area with enough margin to allow for planned outages.

5.2.3 Niagara Zone

Completion of the transmission reinforcements from the Niagara region into the Hamilton-Burlington area continues to be delayed, and the transmission congestion continues to restrict the connection of new generation. This project, if completed, would increase the transfer capability from the Niagara region to the rest of the Ontario system by approximately 700 MW.

5.2.4 East Zone and Ottawa Zone

There is an increased possibility that imports may need to be restricted during peak load periods because of two factors: further increases in the amount of load supplied from the 230 kV system in the Merivale area, and a minimum threshold of 400 MW on the level to which the transfers from Hydro Quebec can be automatically reduced following the loss of one of the 230 kV Hawthorne-to-Merivale circuits. The situation may be especially challenging during periods of low hydroelectric output from the plants on the Ottawa and Madawaska Rivers, which is not uncommon during summer peak periods. Hydro One is planning to reinforce the Hawthorne to Merivale circuits by upgrading their conductors to address this issue. This project is currently planned to be in-service by Q1 2020.

Transmission transfer capability in the East and Ottawa zones is expected to be sufficient for the purpose of supplying load in these areas with sufficient margin to allow for planned outages.

5.2.5 West Zone

Transmission constraints in this zone may restrict resources in southwestern Ontario. This is evident in the constrained generation amounts shown for the Bruce and West zones in Tables A3 and A6.

Transmission transfer capability into the West zone is expected to be sufficient to supply load in this area with enough margin to allow for planned outages.

5.2.6 Northeast and Northwest Zones

Work to modify the existing line-connected reactors at Hanmer TS continues.This modification will allow for post-contingency switching of these reactors to occur, thereby increasing the transfer capability of the Flow South Interface. The estimated completion date for the first reactor is Q3 2016, with the second one sometime after Q1 2017.

Following the expansion of the Mattagami River plants, increased transfers are being experienced from the 230 kV system to the 115 kV system at Kapuskasing TS. Because of these higher transfers, combined with the output from the 30 MW of new hydroelectric and solar projects in the Kapuskasing area, the thermal capability of the 115 kV transmission facility between Hunta and Kapuskasing is expected to be exceeded. To ensure that the existing level of supply reliability is maintained, it is expected that some of the generating facilities in the Kapuskasing area will need to be constrained-off whenever these high transfers occur. Hydro One is currently evaluating a potential solution to increase the thermal capability of the limiting 115 kV transmission facility between Hunta and Kapuskasing that would address this issue.

The limited reactive absorption facilities that are available in the Timmins area are proving to be an obstacle to the restoration of the system in the northeast following an outage involving either of the 500 kV circuits. Maintaining voltages below the agreed maximum of 550 kV during the restoration process before the system can be loaded has been challenging, particularly with the reduction that has occurred to the loads in the Timmins area.

Transmission constraints may restrict resources in northwestern Ontario. This is evident in the constrained generation amounts shown for the Northwest zone in Tables A3 and A6. The upcoming East-West Tie expansion project will help address these constraints. This project is currently scheduled to be in-service by 2020. Transmission transfer capability in the Northeast and Northwest zones is expected to be sufficient to supply the existing load in this area with enough margin to allow for planned outages.

- End of Section -

6 Operability

This section highlights any existing or emerging operability issues that could potentially impact the system reliability of Ontario's power system.

6.1 Storage

At the end of 2015, nine energy storage projects totaling 16.75 MW were offered 10-year contracts for capacity services as part of the Phase II energy storage competitive procurement process. This complements the approximately 34 MW storage procured in Phase I by the IESO to offer ancillary services to support increased reliability and efficiency of the grid. Once they become operational, these procurements are intended to support the province's efforts to better understand the integration and operation of energy storage in Ontario's electricity system and markets. The first of the Phase I projects are expected to become operational in the latter part of 2016.

6.2 Surplus Baseload Generation (SBG)

Baseload generation is made up of nuclear, run-of-the-river hydroelectric and variable generation such as wind and solar. When the baseload supply is expected to exceed Ontario demand, the system is balanced using market mechanisms, which include export scheduling, the dispatch of hydroelectric generation and grid-connected renewable resources, and nuclear manoeuvering or shutdown. In addition, out-of-market mechanisms such as import cuts and curtailment of linked wheels could also be utilized to alleviate SBG conditions. These actions usually, but not always, occur when Ontario demand is at its lowest.

Figure 6.1 shows the nuclear, wind and import curtailments from April 2015 to the end of March 2016. The lower demands, high nuclear availability and the increasing amount of wind and solar generation in the system resulted in a high volume of curtailment starting in the fall of 2015. Recent changes were made to the floor prices of solar and wind resources that changed the dispatch order during SBG conditions. Since wind and solar are now dispatched down before nuclear, increases in the proportion of wind curtailments are observed.

Figure 6.1 MWh Curtailments versus Ontario Demand

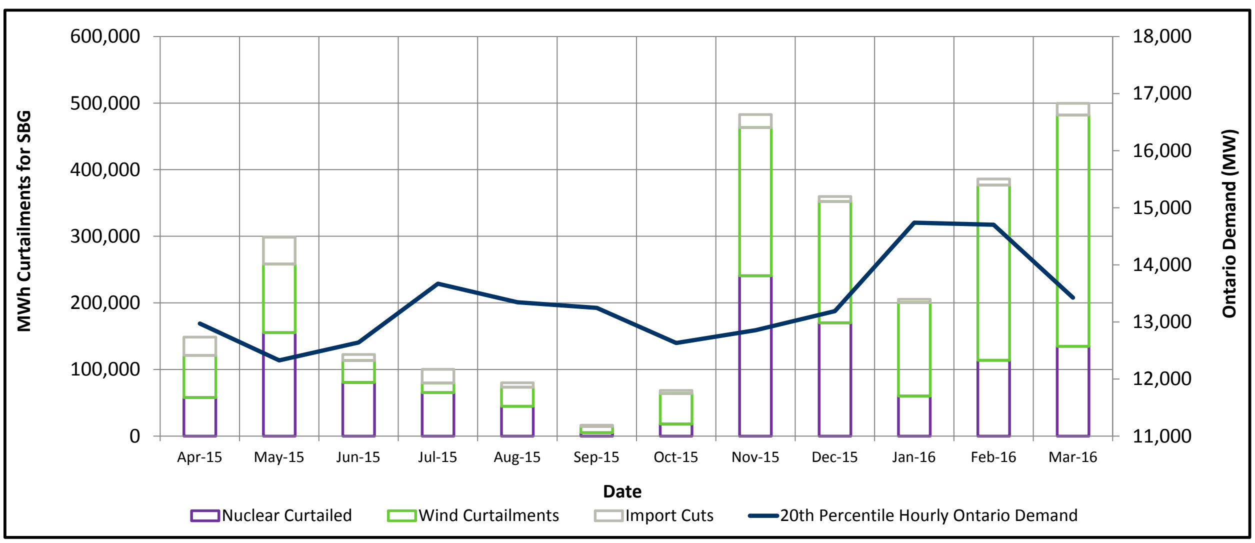
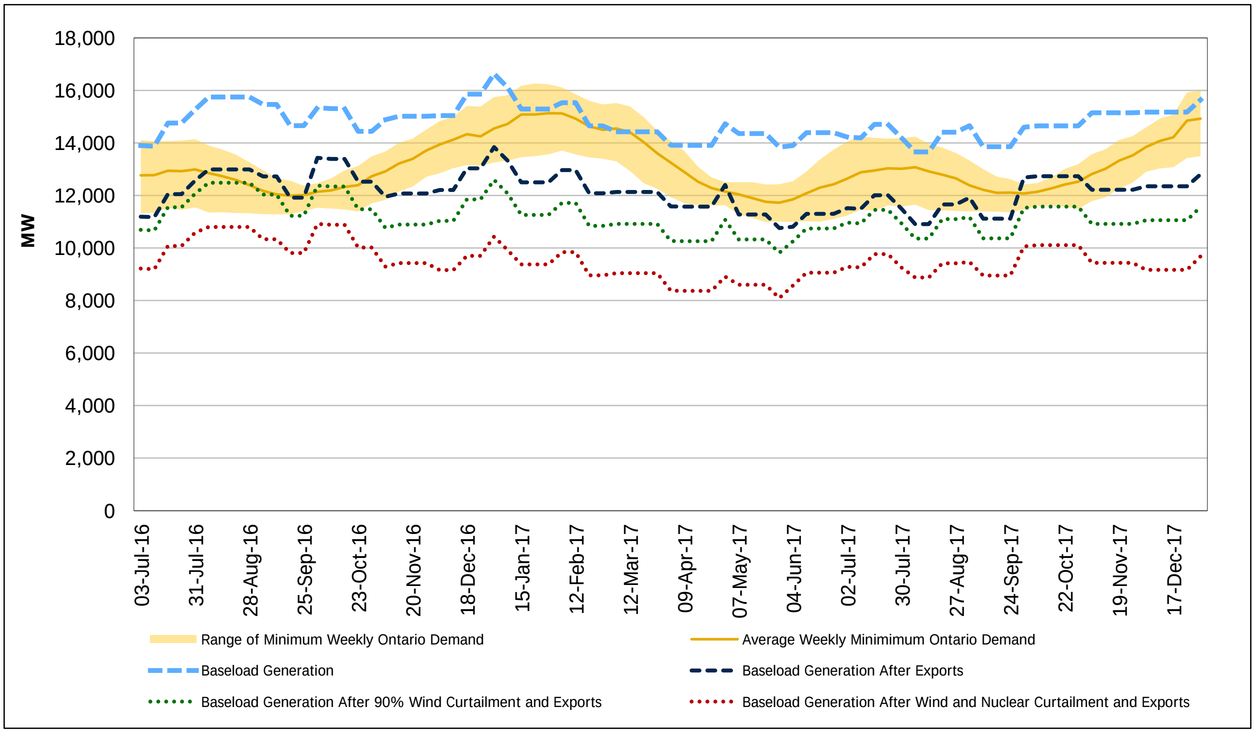


Figure 6.2 shows the forecast SBG for the next 18 months and the flexibility from nuclear, wind and solar generation and exports. The effects of the floor price changes for wind and solar generation from February 2016 are included in the SBG forecast.

Figure 6.2 Minimum Ontario Demand and Baseload Generation



Ontario will continue to experience SBG conditions during the Outlook period, and SBG can be managed through existing market mechanisms.

The baseload generation assumptions include the run-of-river hydroelectric production defined as the bottom 25th percentile of the hourly production in hours 1 through 5, the latest planned outage information, in-service dates for new or refurbished generation, and reliable export capability. The expected contribution from self-scheduling and intermittent generation has also been updated to reflect the latest data. Output from commissioning units is explicitly excluded from this analysis due to uncertainty and the highly variable nature of commissioning schedules. Table 6.1 shows the monthly off-peak wind capacity contribution values calculated from actual wind output up to March 31, 2016. These values are updated annually to coincide with the release of the summer 18-Month Outlook.

Table 6.1: Monthly Off-Peak Wind Capacity Contribution Values

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Off-Peak WCC (% of Installed Capacity)	33.5%	33.5%	31.5%	34.2%	24.1%	15.4%	15.4%	15.4%	21.6%	28.4%	33.1%	33.5%

6.3 Operability Assessment

As part of its regular review of system operability, the IESO conducts assessments to identify areas of potential operability concerns. In the most recent operability assessments, the IESO examined the impact of uncertainty in the time-frames in which the IESO typically commits or dispatches resources to balance supply and demand. This review confirmed recent trends observed in real-time operations:

- Over-forecasting of wind and solar generation output day-ahead, ~5 hours ahead and 1 hour ahead of real-time can lead to under-commitment of Ontario generators and under-scheduling of imports. These forecast inaccuracies increase as the size of this fleet increases, driving the need for enhanced flexibility from Ontario resources to respond to these short-term differences between expected and actual production. The need for flexibility has been experienced in other jurisdictions where a variety of solutions have been employed. The IESO has recently launched a stakeholder initiative to present its findings and discuss potential long-term solutions.
- Differences between actual and expected results in real-time can come from a variety of sources, including inaccuracies in the forecast of demand, inaccuracies in the forecast of wind and solar generation output, resources that ramp faster/slower than expected and resources that don't meet dispatch targets. These differences are addressed by regulation service. The IESO's assessment of operability found that regulation resources are frequently pinned at their high or low limits. As a result, the IESO is seeking to expand the depth of the regulation service market in Ontario. As a first step, the IESO will soon be conducting a Request for Information (RFI) that will be open to both incumbent providers and potential new entrants into the regulation service marketplace.

The assessment of operability also found that reduction of the load on the grid and change in patterns of demand creates high voltages at times that require special control actions to be managed. This drives a need for enhanced mechanisms to manage system voltage, both during steady-state operation and after a power system event. While the IESO and Hydro One are currently managing this situation with day-to-day operating procedures, work to identify long-term solutions continues.

The recent operability review reinforces the need for a diverse portfolio of resources that contributes to the reliability of the grid, including consideration of operational impacts in addition to addressing overall adequacy. The mix of supply options must be capable of meeting peak demand requirements and provide sufficient energy capability to be sustainable under a variety of conditions, including extreme weather events.

Today, the existing intermediate and peaking generation in Ontario consists mainly of generation fuelled by gas, oil and those hydroelectric generators with storage capability.

Intermediate generation substantially contributes to meet energy and peak needs for upwards of 16 hours per day and has desirable operating characteristics due to its dispatch capability. Peaking generation does not necessarily have the energy sustainability of intermediate generation, but is important for meeting peak requirements, for supplying operating reserves and for short-term supply/demand balancing during daily load-pickup and drop-off.

It is important that the supply mix remain robust in meeting industry planning standards, flexible to meet the ever-changing demands of system operations and balanced in managing inherent risks, such as fuel security and critical infrastructure needs.

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