

18-Month Outlook

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

FROM JANUARY 2017 TO JUNE 2018

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 under normal weather conditions.

Under extreme weather conditions, the reserve levels are below requirement for 14 weeks over the 2017 summer period due to planned generator maintenance. If extreme weather conditions materialize, the IESO may need to reject some generator maintenance outages to ensure that Ontario demand is met during the summer peak. Therefore, generators expecting to perform maintenance during the summer of 2017 should understand that those outages are at risk and are advised to review their maintenance plans and reschedule them.

Peak demand continues to face downward pressure due to conservation savings, growing embedded generation output and the Industrial Conservation Initiative (ICI). Effective January 1, 2017, ICI eligibility will be expanded by lowering the threshold for participation and expanding eligibility to all sectors.

Annual energy demand is expected to show a slight increase in 2016 due primarily to the additional leap year day. Though Ontario's economy has picked up momentum, the growth has been balanced with reductions in electricity demand due to the reasons cited above. Demand is expected to remain flat over the Outlook period as further economic growth is balanced by additional demand reductions coming from conservation.

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

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2016-17	21,914	23,170
Summer 2017	22,512	24,851
Winter 2017-18	21,811	23,017

About 2,000 megawatts (MW) of new supply – 550 MW of wind, 1,300 MW of gas, 50 MW of hydroelectric and 100 MW of solar generation – is expected to be connected to the province's transmission grid over the Outlook period. Contracts for approximately 260 MW of non-utility generators (NUGs) are expiring but at least 140 MW will remain in the planned scenario where forecast data has been provided by the generator beyond the contract expiration date. 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 650 MW. Meanwhile, embedded solar generation is expected to increase to over 2,100 MW.

As part of the electricity trade agreement between Ontario and Quebec announced in October 2016, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. In addition, Ontario will receive up to two terawatt hours of clean energy annually. The imported energy will be targeting peak hours to help reduce greenhouse gas (GHG) emissions in Ontario.

The New York Independent System Operator (NYISO) Winter 2016/2017 capacity auction was held in September 2016 to secure capacity for New York for the six-month commitment period from November 2016 to April 2017. The NYISO auction cleared 88 MW of Ontario generation.

On August 21, 2017, a total solar eclipse is expected to pass over parts of the continental U.S. and Canada. Although Ontario will only see a partial eclipse, this event is expected to impact operations because a decline in embedded solar production will lead to a corresponding increase in grid demand. The IESO will be working closely with market participants and interconnected Reliability Coordinators to ensure reliable operation before, during and after this meteorological event.

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 decline throughout the period of this Outlook. For the winter peaks, downward pressure stems from conservation and price pressures whereas the summer peaks also have additional downward pressure from the ICI and increased output from embedded solar. Supplied energy faces the same drivers and is not expected to grow over the forecast horizon.

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 19 weeks over the entire Outlook period, with the largest shortfall being approximately 3,000 MW. The firm scenario excludes any new generating facilities that haven't reached commercial operation. If 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 15 weeks over the entire Outlook period, with the largest shortfall being around 2,400 MW.

Transmission Adequacy

Ontario's transmission system is expected to be able to reliably supply Ontario 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 kilovolt (kV) system are markedly reduced as a result of medium-to-low load conditions combined with the effect of transactions through the interconnections with Ontario's neighbouring jurisdictions, periods of high

voltages can occur. While the IESO and Hydro One are currently managing this situation with day-to-day operating procedures, both parties are working on the plan to install additional new high voltage reactors at Lennox transformer station (TS) to address this issue. Work to finalize the details of this project is ongoing; the expected in-service date of this project continues to be mid-2020.

- There is a possibility that imports from Hydro Quebec may need to be restricted in Eastern Ontario due to the thermal limitations imposed on the 230 kV Hawthorne-to-Merivale circuits. As requested by the IESO, Hydro One is planning to increase the rating of the Hawthorne-to-Merivale 230 kV circuits, which are part of the transmission network path between Eastern Ontario and the major load centers near the GTA area. This project, currently planned to be completed by Q1 2020, also includes replacing the under-rated line disconnect switches at Hawthorne TS.
- During peak load periods, the two under-sized autotransformers at Hawthorne TS are expected to be overloaded post-contingency. As per the recommended solution in the IESO's Integrated Regional Resource Plan (IRRP) for the Ottawa area, Hydro One is proceeding with the replacement of these transformers with standard-sized units; the expected completion date for this work remains Q2 2018.
- A new transformer station, Copeland TS, is now planned to be in-service in downtown Toronto in Q1 2018. 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. 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 address the various reliability requirements of the grid. The IESO plans to expand its capability to schedule regulation by increasing the amount of regulation usually scheduled from 100 MW to 150 - 200 MW between 2017 and 2019 and have sufficient market depth to schedule up to 250 to 300 MW of regulation capacity on an as-needed basis by the year 2020.

Caution and Disclaimer

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1 Introduction

This Outlook covers the 18-month period from January 2017 to June 2018 and supersedes the last Outlook released on September 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.
- To report on initiatives being put in place to improve reliability within the 18-month timeframe of this Outlook.

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.

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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 September 2016. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for October and November 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 outage management system as of October 25, 2016.

This report period incorporates a number of outages, as identified in Table A8 of the [2016 Q4 Outlook Tables](#), including the commencement of the nuclear refurbishment program.

As of October 25, 2016, the following generator completed the market registration process since the last Outlook:

- Lower White River Generating Station – 10.1 MW
- Upper White River Generating Station – 8.8 MW
- GenSet Resource Management Inc. added a generator with 0.8 MW to their fleet.

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 outage management system as of October 25, 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 outage management system as of October 25, 2016.

- End of Section -

3 Demand Forecast

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period January 2017 to June 2018 and supersedes the previous forecast released in September 2016. Tables of supporting information are contained in the [2016 Q4 Outlook Tables](#) spreadsheet.

Electricity demand is shaped by a several factors, which have differing impacts; those that increase the demand for electricity (population growth, economic expansion and the increased penetration of end-uses); those that reduce the need for grid supplied electricity (conservation and embedded generation), and those that shift demand (time of use rates and the Industrial Conservation Initiative (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 remain virtually flat over the forecast horizon. For 2016, demand is projected to show a small increase (0.5 percent), but this is primarily due to the additional leap day. Underlying fundamentals – a low dollar, strong U.S. growth, low interest rates and low inflation – would indicate an improving economy. However, the extent to which recent political events, such as Brexit and the U.S. election, results impact Canada’s export opportunities is still unknown.

Peak demands are subject to the same forces as energy demand, though the impacts vary. This is true not only when comparing energy versus peak demand, but also in comparing the summer and winter peak. Summer peaks are significantly impacted by the growth in embedded solar generation capacity and pricing impacts (ICI and time-of-use rates). In addition to reducing summer peaks, increased embedded solar output is also pushing the peak to later in the day. Winter peaks face less downward pressure from embedded generation than they do from conservation. Since the winter peaks occur after sundown, improvement to lighting efficiency impact winter peaks.

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)
Winter 2016-17	21,914	23,170
Summer 2017	22,512	24,851
Winter 2017-18	21,811	23,017
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	136.2	-1.9%
2016 Energy (Forecast)	136.7	0.4%
2017 Energy (Forecast)	137.1	0.3%

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)
08-Jan-17	21,371	22,280	570	2,838	08-Oct-17	17,521	17,704	786	2,453
15-Jan-17	21,914	23,170	547	2,917	15-Oct-17	17,489	17,628	507	2,435
22-Jan-17	21,576	22,168	483	2,907	22-Oct-17	17,814	18,302	392	2,472
29-Jan-17	21,416	22,341	404	2,912	29-Oct-17	17,951	18,546	318	2,513
05-Feb-17	21,064	22,285	734	2,916	05-Nov-17	18,172	18,899	416	2,522
12-Feb-17	20,465	22,084	635	2,859	12-Nov-17	19,276	19,845	601	2,628
19-Feb-17	20,172	21,722	581	2,806	19-Nov-17	19,564	20,356	342	2,646
26-Feb-17	19,836	21,752	501	2,755	26-Nov-17	20,006	20,792	607	2,719
05-Mar-17	20,126	21,500	531	2,776	03-Dec-17	20,414	21,496	409	2,767
12-Mar-17	19,834	20,814	649	2,738	10-Dec-17	20,568	21,766	555	2,794
19-Mar-17	18,793	19,645	611	2,662	17-Dec-17	20,918	21,991	690	2,838
26-Mar-17	18,343	19,242	569	2,572	24-Dec-17	20,755	21,909	362	2,807
02-Apr-17	18,222	19,344	567	2,555	31-Dec-17	20,507	21,726	528	2,713
09-Apr-17	18,000	18,688	471	2,521	07-Jan-18	21,238	21,989	570	2,835
16-Apr-17	17,244	18,364	496	2,414	14-Jan-18	21,811	23,017	547	2,902
23-Apr-17	16,747	16,838	531	2,402	21-Jan-18	21,381	21,874	483	2,890
30-Apr-17	16,791	17,336	721	2,392	28-Jan-18	21,221	22,047	404	2,896
07-May-17	17,532	20,472	849	2,364	04-Feb-18	21,068	22,218	734	2,904
14-May-17	17,687	20,013	845	2,378	11-Feb-18	20,322	21,791	635	2,842
21-May-17	18,698	22,089	1,175	2,405	18-Feb-18	20,046	21,446	581	2,792
28-May-17	18,625	22,275	1,330	2,354	25-Feb-18	19,787	21,460	501	2,740
04-Jun-17	19,224	21,802	1,292	2,448	04-Mar-18	20,175	21,501	531	2,770
11-Jun-17	19,883	24,308	1,055	2,584	11-Mar-18	19,735	20,564	649	2,725
18-Jun-17	20,911	24,428	835	2,601	18-Mar-18	18,666	19,365	611	2,649
25-Jun-17	22,403	24,604	754	2,665	25-Mar-18	18,221	18,972	569	2,560
02-Jul-17	22,220	24,105	1,016	2,644	01-Apr-18	18,109	19,081	567	2,507
09-Jul-17	22,512	24,851	814	2,727	08-Apr-18	17,907	18,446	471	2,501
16-Jul-17	22,216	23,923	838	2,758	15-Apr-18	17,158	18,131	496	2,446
23-Jul-17	21,960	23,906	1,035	2,655	22-Apr-18	16,712	16,942	531	2,404
30-Jul-17	22,000	24,684	841	2,741	29-Apr-18	16,711	17,097	721	2,383
06-Aug-17	22,276	24,466	958	2,759	06-May-18	17,443	20,235	849	2,355
13-Aug-17	21,866	24,575	985	2,713	13-May-18	17,586	19,768	845	2,369
20-Aug-17	21,291	24,433	1,362	2,688	20-May-18	18,412	21,853	1,175	2,397
27-Aug-17	21,289	23,457	1,413	2,691	27-May-18	18,490	22,042	1,330	2,345
03-Sep-17	20,508	23,092	1,370	2,574	03-Jun-18	19,136	21,711	1,292	2,428
10-Sep-17	18,821	22,264	680	2,421	10-Jun-18	19,793	24,212	1,055	2,572
17-Sep-17	19,275	21,047	781	2,485	17-Jun-18	20,781	24,302	835	2,588
24-Sep-17	17,985	20,151	420	2,452	24-Jun-18	22,302	24,506	754	2,652
01-Oct-17	17,272	18,678	554	2,397	01-Jul-18	22,316	24,200	1,016	2,689

3.1 Actual Weather and Demand

Since the last forecast the actual demand and weather data for September, October and November have been recorded.

September

- September was much warmer than usual ranking in the top five of the past fifty years. Despite the heat and humidity it was actually slightly cooler than September 2015.
- The month's peak occurred on the hottest day of the month as temperatures topped 34.5°C (at Toronto) and the humidex exceeded 44°C. The peak of 23,213 MW occurred on September 7. The actual peak was highest since 2010.

- The weather corrected peak was a much lower 20,000 MW, but was still the highest since 2013.
- Energy demand for the month was 11.1 TWh (10.8 TWh weather corrected), which is a small decline from last September which was slightly warmer. The weather corrected amount is similar to post-2008 experience for the month.
- The minimum demand for the month was 10,855 MW, which is the lowest value for the month since market opening. The minimum occurred early Sunday, September 25 at 4:00 a.m. EST.
- Embedded generation for the month was 539 GWh, an increase of 5.1 percent over the previous September and was driven by double digit increases in both solar and wind output as reported by distributors.
- Wholesale customers' consumption for the month increased by 0.5 percent compared to the previous September. Mining and chemicals drove the increase.

October

- The weather for October was mixed. The coldest ten days were colder than normal but the rest of the month was significantly milder than normal.
- The peak occurred on October 27, which was the third coldest day of the month. The actual peak was 18,189 MW (17,918 MW weather corrected). The actual is on the lower side of experience since the recession. The weather corrected value represents the lowest October peak since market opening.
- Energy demand for the month was 10.5 TWh (10.6 TWh weather corrected). Both of these are the lowest monthly energy demands since market opening.
- The minimum was 10,663 MW and occurred in the early morning of Sunday, October 16 on a warm weekend. The minimum was an increase over the previous October.
- Embedded generation, as reported by distributors, was 459 GWh for the month. This represents an 11% decrease over the previous November. The decline was attributable to a drastic reduction in non-contracted embedded generation. Both embedded solar (11%) and wind (16%) showed gains over the previous October.

November

- November was milder than normal. The actual peak for November was 19,369 MW occurring on Wednesday November 23, which was the second coldest day of the month. The weather-corrected value was a higher 19,937 MW. Both represent an increase over the previous November.
- With the impacts of conservation and embedded generation, combined with mild weather, actual demand was 10.7 TWh about the same as last year. Weather-corrected demand was higher 11.0 TWh. Both numbers are low by historical standards.
- Minimum demand of 11,211 MW occurred Sunday, November 6 at both 3 and 4 a.m. As the temperature drops the minimums tend to increase as heating load runs overnight. The minimum was triggered by warm temperatures and the weekend. It is the lowest November minimum since market opening.

- Embedded generation reported by distributors was 433 GWh for the month, a decrease of 11% over the previous November. Solar generation was up 6% but wind fell by 12% compared to a year earlier. Non-contracted generation also showed significant declines.
- Wholesale customer consumption increased by 2.8 percent compared to the previous November.

2016 Fall Actuals

Overall, energy demand for the three months from September to November was down 1.4 percent compared with the same three months one year prior. After adjusting for the weather, demand for the three months showed a more modest decline of 0.7 percent.

Embedded generation for the fall months was down 5 percent over the previous fall. Embedded solar output increased by 13% and embedded wind output was flat. The decline came from a reduction in the output of non-contracted embedded generation.

For the three months, wholesale customers' consumption remained flat posting a 0.1 percent increase compared to the previous fall. Increased consumption by the mining and chemical sectors were offset by declines in iron and steel.

The [2016 Q4 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

It is fair to say that the economic outlook is quite clouded at this point in time. Underlying growth had been modest but positive throughout the first three quarters of 2016. However, Britain's decision to leave the European Union and the transition to a new President of the United States could potentially add uncertainty to global markets and impact growth.

Table 3.3.4 of the [2016 Q4 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 Q4 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 Time of Use (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. Early estimates have the ICI peaks for the summer of 2016 in excess of 1,200 MW.

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 registration process since the previous Outlook. 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 October 25, 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	10,667	5	0	0
Hydroelectric	8,451	5,864	73	19	2
Gas/Oil	9,943	8,170	30	1	0
Wind	3,923	479	34	0	0
Biofuel	495	459	9	0	0
Solar	280	28	6	0	0
Total	36,070	25,667	157	20	2

4.1 Assessment Assumptions

4.1.1 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 generation projects in the IESO's Connection Assessment and Approval process (CAA), those that are under construction, as well as contracted resources. 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 October 25, 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 Generation Resources Status

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
Harmon Unit 2 Runner Upgrade		Northeast	Water	2016-Q4	Commissioning		10
Greenfield South	Green Electron Power	West	Gas	2016-Q4	Commissioning		298
Namewaminikan Hydro		Northwest	Water	2016-Q4	Under Development		10
Niagara Region Wind Farm	West Lincoln NRWF	Southwest	Wind	2017-Q1	Commissioning		230
Windsor Solar		West	Solar	2017-Q1	Commissioning		50
Kingston Cogen		East	Gas	2017-Q1	Expiring Contract	-140	
Peter Sutherland Senior Generating Station		Northeast	Water	2017-Q2	Under Development		28
South Gate Solar		Southwest	Solar	2017-Q2	Under Development		50
Harmon Unit 1 Runner Upgrade		Northeast	Water	2017-Q3	Under Development		10
Belle River Wind		West	Wind	2017-Q3	Under Development		100
Napanee Generating Station		East	Gas	2017-Q4	Under Development		985
North Kent Wind 1		West	Wind	2017-Q4	Under Development		100
Kapuskasing Generating Station		Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
North Bay Generating Station		Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
Amherst Island Wind		East	Wind	2018-Q2	Under Development		75
Total						-201	1,886

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**Hydroelectric**

Monthly hydroelectric generation output forecast is calculated based on median historical values of hydroelectric production and contribution to operating reserve during weekday peak demand hours. Through this method, routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data. Table 4.3 shows the historical hydroelectric median values calculated with 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 for Normal Weather Conditions

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

A recent review of historical hydroelectric production data during extreme summer weather years showed that forecasts based on median values for all years in the sample (2002 – 2016) overstates the availability of hydroelectric production during those summer extremes. To more accurately reflect hydroelectric production in the extreme weather scenario, the median contribution of the hydroelectric fleet at the time of peak for summer months (June to

September) is based on 2012 – the driest year in the past 10 years. This is estimated to be about 800 MW lower than the values for normal weather conditions. The methodology to calculate the hydroelectric contribution at varying conditions is continuing to evolve to reflect the actual experience.

Thermal Generators

Thermal generators' capacity, planned outages and deratings are based on market participant submissions. Forced outage rates on demand are calculated by the IESO based on actual operations data. The IESO will continue to rely on market participant submitted forced outage rates for comparison purposes.

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.

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.

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%

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 supply resources and are therefore included in the supply mix. The impact of demand measure activations are added back into the demand history prior to forecasting demand for future periods.

The DR capacity acquired through the DR auction in December 2015 is reflected in the Outlook. The next DR auction will be held in December 2016, with a target capacity of 393 MW for both six-month periods, the summer commitment period beginning on May 1, 2017 and winter commitment period beginning on November 1, 2017.

4.1.4 Firm Transactions

As part of the electricity trade agreement between Ontario and Quebec announced in October 2016, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. In addition, Ontario will receive up to two terawatt hours of clean energy annually. The imported energy will be targeting peak hours to help reduce greenhouse gas (GHG) emissions in Ontario.

The New York Independent System Operator (NYISO) Winter 2016/2017 capacity auction was held in September 2016 to secure capacity for New York for the six-month commitment period from November 2016 to April 2017. The NYISO auction cleared 88 MW of Ontario generation.

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)	36,070	
New Generation and Capacity Changes (MW)	1,886	-201

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	Winter Peak 2017		Summer Peak 2017		Winter Peak 2018	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,130	36,448	35,990	36,806	35,869	37,881
2	Total Reductions in Resources (MW)	8,101	7,981	10,596	10,876	8,227	8,530
3	Demand Measures (MW)	692	692	680	680	662	662
4	Firm Imports (+) / Exports (-) (MW)	-588	-588	0	0	-500	-500
5	Available Resources (MW)	28,133	28,572	26,074	26,610	27,805	29,513

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

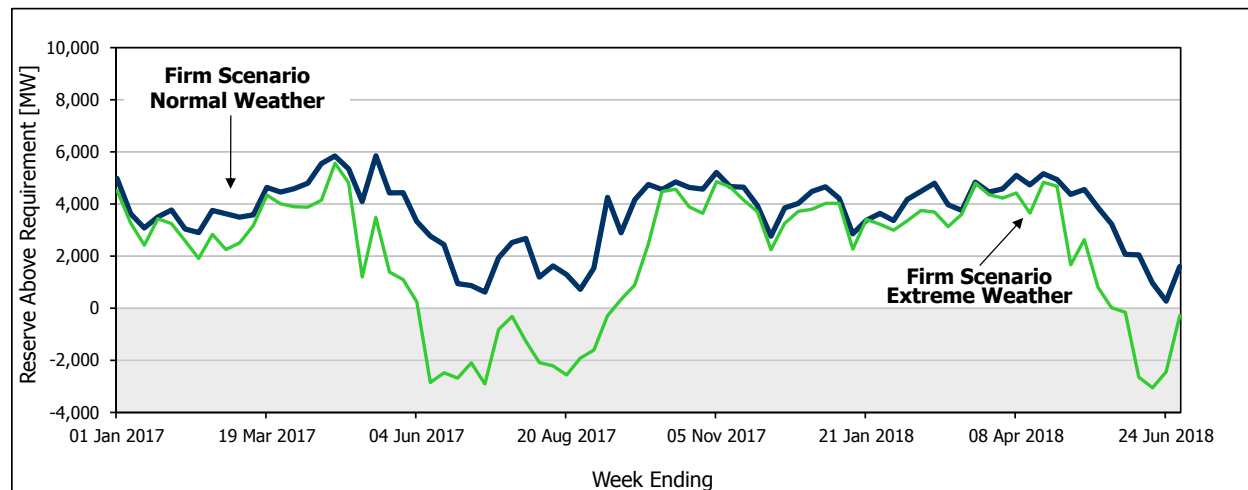
The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages. The planned outages occurring during this Outlook period have been assessed as of October 25, 2016.

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 October 25, 2016. Roughly 60 MW of wind capacity have achieved 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 19 weeks during the 18-Month Outlook timeframe. This shortfall is largely attributed to the planned generator outages scheduled during those weeks. If extreme weather conditions do materialize, the IESO may need to reject some generator maintenance outage requests to ensure that Ontario demand is met during the summer peak. Therefore, generators expected to perform maintenance on their units during the summer of 2017 should understand that those outages are at risk and are advised to review their planned maintenance plans and reschedule them if they are critical for the continued operation of the units.

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

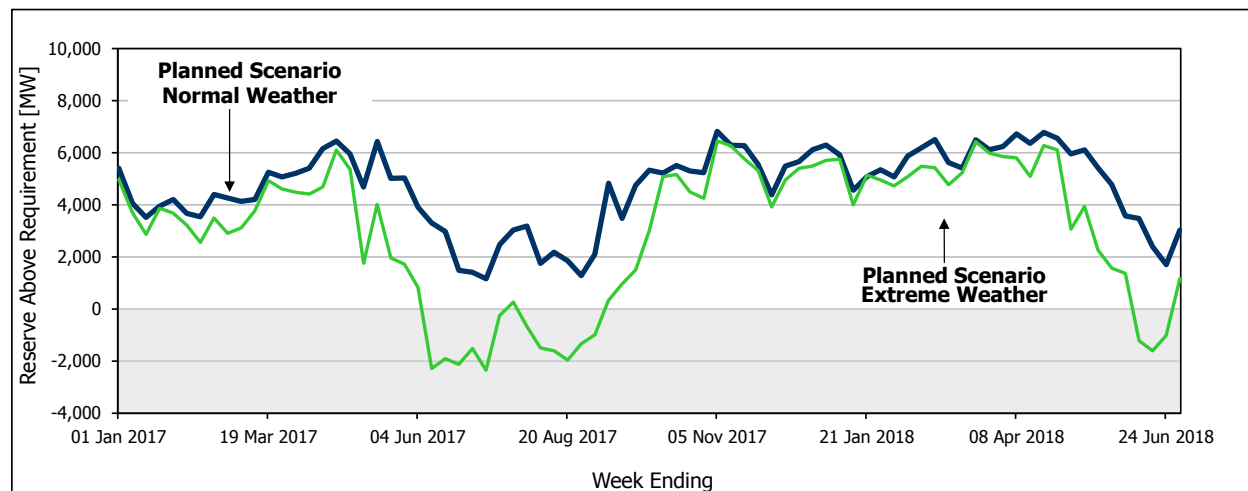


4.2.2 Planned Scenario with Normal and Extreme Weather

The **planned scenario** incorporates all existing capacity plus all capacity coming in service. Approximately 1,900 MW of net 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 15 weeks during the 18-Month Outlook timeframe under extreme weather conditions. This shortfall is largely attributed to the planned outages scheduled for those weeks.

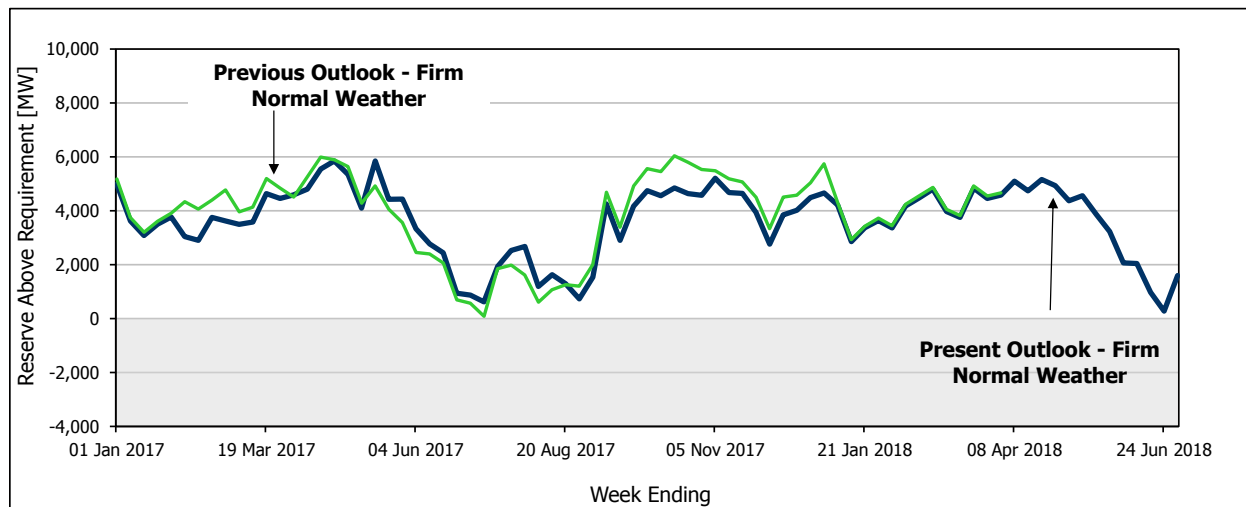
Figure 4.2: Normal vs. Extreme Weather: Planned Scenario RAR



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 September 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 ‘Generation Resources Status’ for this information. The monthly forecast of energy production capability, based on the energy modelling results, is included in Table A7 of the [2016 Q4 Outlook Tables](#).

For the EAA, only the **firm 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 – Firm Scenario with Normal Weather

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

Table 4.8: Firm 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	205.0	15,641	205.0	15,641	0.0	451.0	577.0
Bruce	1.0	75	70.9	5,407	69.9	1.3	165.8
East	12.3	940	14.9	1,133	2.6	25.1	77.6
Essa	11.9	910	3.8	288	-8.1	24.8	14.2
Niagara	6.0	461	19.8	1,512	13.8	14.3	41.2
Northeast	14.9	1,136	15.0	1,148	0.1	24.1	29.2
Northwest	5.9	451	6.2	475	0.3	9.9	22.2
Ottawa	12.8	979	0.0	3	-12.8	26.1	2.1
Southwest	42.6	3,247	6.0	461	-36.6	94.7	24.7
Toronto	77.4	5,904	59.9	4,570	-17.5	182.7	128.5
West	20.1	1,537	8.4	644	-11.7	48.0	71.6

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 firm scenario with normal weather demand, with no anticipated reliance on support from external jurisdictions.

Figure 4.4 shows the percentage production by fuel type to supply Ontario energy demand 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 – Jan. 1, 2017, to Jun. 30, 2018

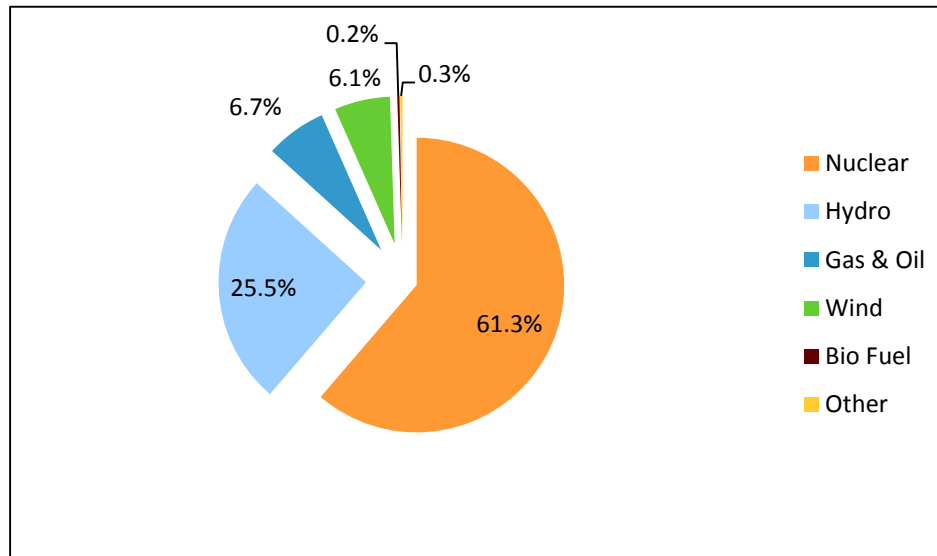


Figure 4.5: Monthly Production by Fuel Type – Jan. 1, 2017, to Jun. 30, 2018

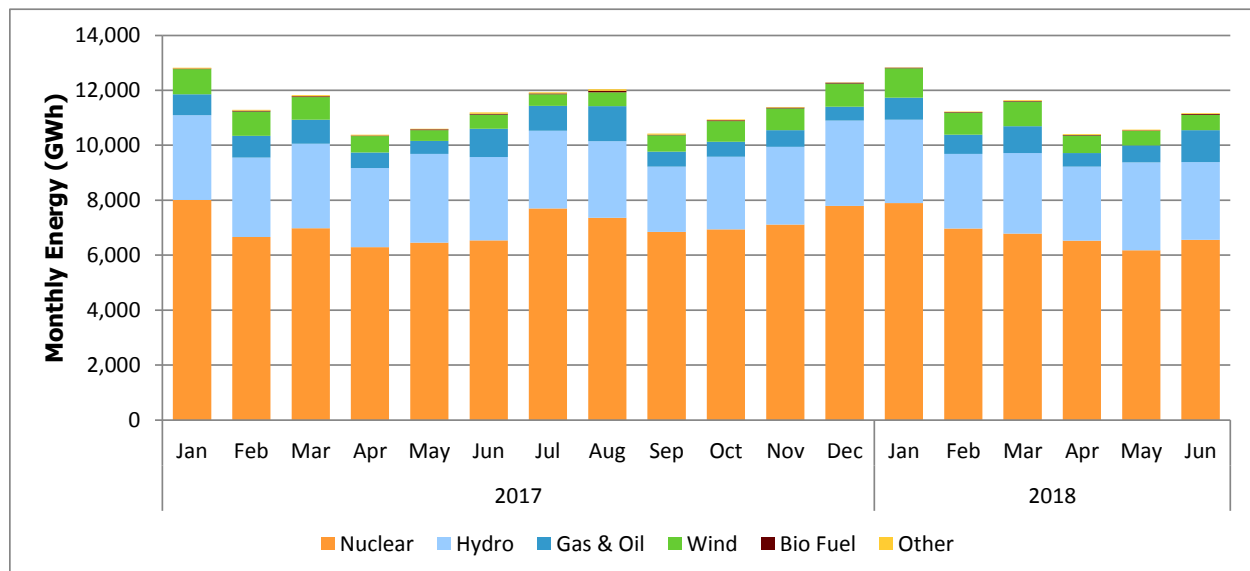


Table 4.9: Firm Scenario - Normal Weather: Ontario Energy Production by Fuel Type

Fuel Type (Grid Connected)	2017 (Jan 1 – Dec 31)	2018 (Jan 1 – Jun 30)	Total
	(GWh)	(GWh)	(GWh)
Nuclear	84,684	40,913	125,597
Hydro	34,762	17,405	52,167
Gas & Oil	8,898	4,755	13,653
Wind	8,016	4,477	12,493
Bio Fuel	368	135	503
Other (Solar & DR)	401	142	543
Total	137,129	67,827	204,956

- 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 transmission projects that are considered major modifications or significant improvements to 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 C11](#). 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 October 25, 2016.

5.2 Transmission System Adequacy

The IESO assesses transmission adequacy using the methodology based on 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 capable of supplying the demand under the normal and extreme 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 with projects being initiated to address local area needs. For additional information on IESO's regional planning activities, 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.

Due to the existing switching arrangement at both Manby East and Manby West TS, the failure of a single breaker to operate as intended can result in two autotransformers being removed from service simultaneously. With the expected increase in load resulting from the proposed electrification of the GO Train System, the remaining autotransformer could potentially be overloaded during peak load periods. A load rejection scheme, which will help minimize customer service interruptions while alleviating these overloads, is expected to be in service by

Q2 2018. This scheme will also address the possible overloading that could occur should either of the remaining autotransformers fail while one autotransformer is already out-of-service.

In central Toronto, the expected completion date for Copeland TS is now Q1 2018. 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 neighbouring jurisdictions. Temporary removal from service of at least one of the 500 kV circuits in Eastern Ontario 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, both parties are working on the plan to install additional high voltage reactors at Lennox TS to address this issue. Details of this project are being confirmed and the expected in-service date of this project remains to be mid-2020.

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, as recommended in the York Region IRRP, Hydro One is planning to install two 230 kV in-line breakers at Holland TS, together with a load rejection scheme. These facilities are still expected to be in-service by Q4 2017. Until these facilities become available, operational measures may be required. Once completed, the project will relieve possible overloading of these 230 kV circuits during peak load periods.

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

5.2.2 Bruce and Southwest Zones

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 transmission and generation outages will be needed.

Hydro One is also continuing work on a new Bruce Remedial Action Scheme (RAS), which is now scheduled for completion by December 2017. This new RAS will replace the existing special protection system while having increased functionality to detect and operate for a greater number of system contingencies.

The transmission transfer capability in the Southwest zone and its vicinity is expected to be sufficient to serve 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 a possibility that imports from Hydro Quebec may need to be restricted due to the thermal limitations on the 230 kV Hawthorne-to-Merivale circuits, that are part of the transmission network path from Eastern Ontario towards major load centers near the GTA area. 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 the summer period. Further increases in the amount of load supplied by this network path, such as the load supplied from the 230 kV system in the Merivale area, will also worsen the situation. As requested by the IESO, Hydro One is planning to increase the capability of these 230 kV Hawthorne to Merivale circuits, including the replacement of under-rated line disconnect switches at Hawthorne TS. This project is currently planned to be completed by Q1 2020.

During peak load periods, the two under-sized autotransformers at Hawthorne TS are expected to be overloaded post-contingency. As recommended in the IRRP for Ottawa, Hydro One is proceeding with the replacement of these transformers with standard-sized units and the expected completion date for this work remains to be Q2 2018. Once completed, this project will increase the step-down capability at Hawthorne TS to support the load in its 115 kV system.

Overall transmission transfer capability in the East and Ottawa zones is expected to be sufficient for the purpose of serving 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](#). Additional generation connection is restricted in some parts of this area.

Transmission transfer capability into the West zone is expected to be sufficient to serve 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, thereby increasing the transfer capability of the Flow South Interface. This project is still expected to be complete by the end of 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. These higher transfers, combined with the output from the 30 MW of new hydroelectric and solar projects in the Kapuskasing area, are expected to cause the thermal capability of the 115 kV transmission facility between Huntla and Kapuskasing 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. As recommended by the IESO, Hydro One is finalizing plans to reinforce the system in the Kapuskasing Area. 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 specified

maximum of 550 kV during the restoration process before the system can be loaded has been challenging, particularly with the demand reduction that has occurred 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](#). As a result, additional generation connection is restricted in this area. The upcoming East-West Tie expansion project may help address one of these constraints, however additional constraints in the Sault Ste. Marie and Sudbury areas will continue to limit generation in Northwestern Ontario. This project is currently scheduled to be in-service by 2020.

Transmission constraints are also restricting the connection of additional load in some areas in northwestern Ontario. These restrictions should be addressed by the proposed 230 kV single-circuit line to Pickle Lake which is currently scheduled to be in-service in early 2020.

Transmission transfer capability in the Northeast and Northwest zones is expected to be sufficient to serve 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 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 of grid energy storage procured in Phase I by the IESO to offer ancillary services to support grid reliability. 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. Phase I projects are expected to become operational over the course of 2017.

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 inter-tie scheduling, the dispatch of hydroelectric generation and grid-connected renewable resources, and nuclear manoeuvring 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 October 2015 to the end of September 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.

Figure 6.1 MWh Curtailments versus Ontario Demand

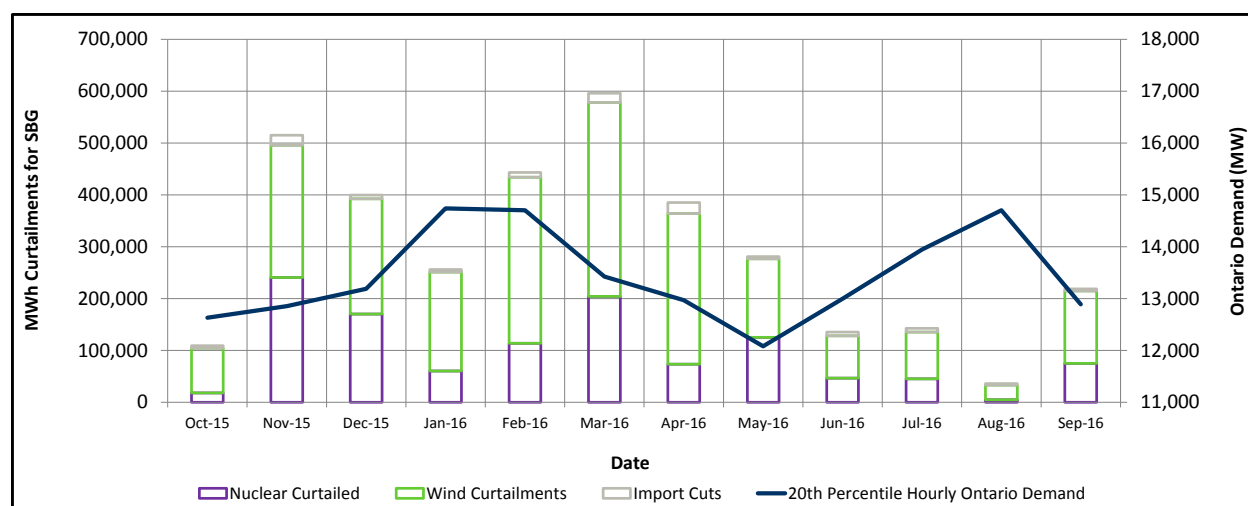
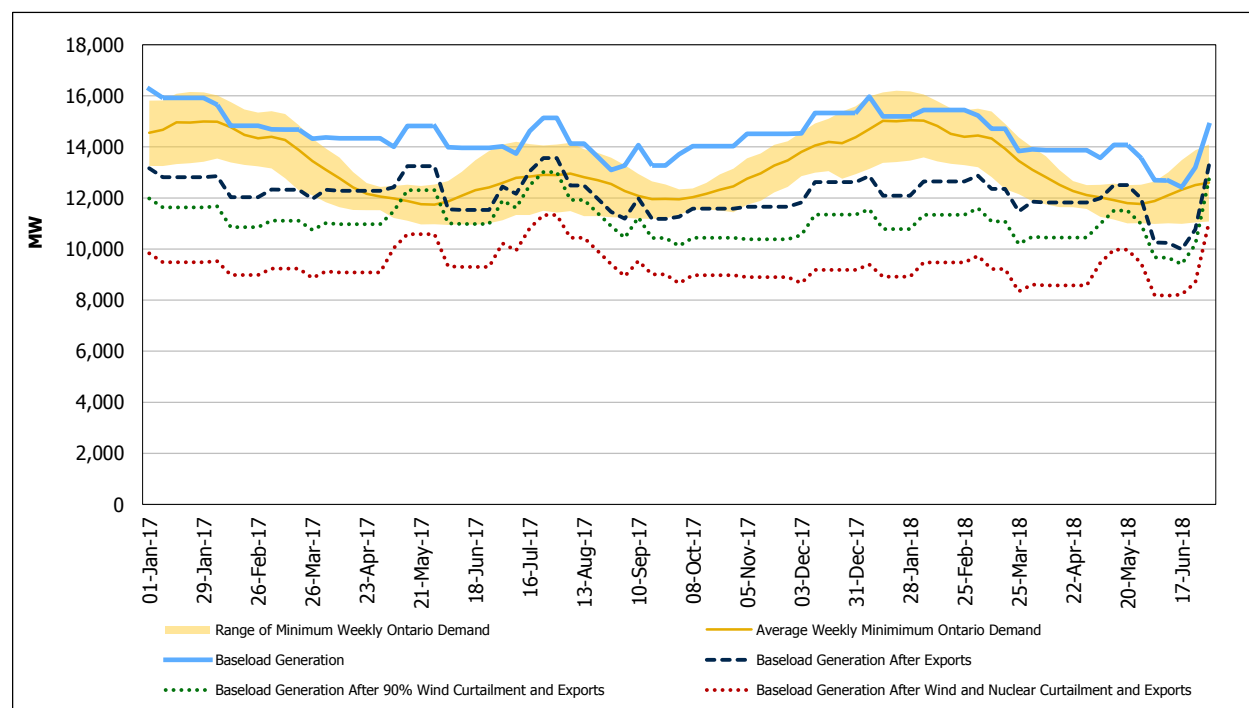


Figure 6.2 shows the forecast SBG for the next 18 months and the flexibility from nuclear, wind and solar generation and exports.

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, 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)	32.8%	32.8%	32.0%	34.5%	24.7%	14.4%	14.4%	14.4%	19.3%	29.4%	32.9%	32.8%

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 timeframes in which the IESO typically commits or dispatches resources to balance supply and demand. This review confirmed recent trends observed in real-time operations:

- Enhanced flexibility from Ontario resources to respond to the short-term differences between expected and actual production becomes increasingly important as the variable generation forms a larger proportion of the supply mix. It is anticipated that an additional 300 MW of flexible resource capability is needed on the system by the end of 2017. By the end of 2018, a further 700 MW of flexible resource capability is required. The IESO has recently launched a stakeholder initiative to present its findings and discuss potential solutions. More information can be found on the Stakeholder Engagement webpage at <http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx>.
- Regulation service acts to match total system generation to total system demand on a second-to-second basis and helps correct variations in power system frequency. The IESO is seeking to expand the depth of the regulation service market in Ontario.

The IESO plans to expand its capability to schedule regulation by increasing the amount of regulation usually scheduled from 100 MW to 150 -200 MW between 2017 and 2019 and have sufficient market depth to schedule up to 250 to 300 MW of regulation capacity on an as-needed basis by the year 2020.

The IESO is seeking to reach this target through:

- one or more competitive procurements between now and 2020 with a view to increasing competition;
- examination of potential additional regulation products to unlock the value of emerging technologies and fast-moving resources; and
- standardized, simplified, regulation agreements that are more in-line with prevailing commercial terms in North American electricity markets.

More information can be found at the Ancillary Services Market webpage at www.ieso.ca/ancillary-services.

- 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 contingency. While the IESO and Hydro One are currently managing this situation with day-to-day operating procedures, work to identify long-term solutions continues.

On August 21, 2017, a total solar eclipse is expected to pass over parts of the continental US and Canada. Although Ontario will only see a partial eclipse, this event is expected to impact operations because a decline in embedded solar production will lead to a corresponding increase in grid demand. The IESO will be working closely with market participants and interconnected Reliability Coordinators to ensure reliable operation before, during and after this meteorological event.

- End of Document -

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