18-Month Outlook

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

FROM JULY 2017 TO DECEMBER 2018

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 domestic generation and transmission to supply Ontario's demand under normal weather conditions.

Under extreme weather conditions, the reserve levels that reflect current planned generator outages are below requirement for a combined total of 29 weeks over the summer periods in 2017 and 2018. 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 should understand that those outages are at risk and are advised to review their maintenance plans and consider rescheduling them.

Peak demand is expected to decline over the forecast period as conservation savings, increased embedded generation output and the Industrial Conservation Initiative (ICI) more than offset underlying growth. Effective January 2017, ICI eligibility has been expanded to include all electricity users with a monthly average peak demand of over 1 megawatt (MW). In April 2017, the threshold was reduced to 500 kilowatts for manufacturers and greenhouses.

Annual energy demand is expected to show a slight decline in 2017 as conservation savings and increased embedded generation output more than offset any growth. Increased demand from population growth and higher levels of economic activity are expected to increase annual energy demand in 2018 relative to 2017.

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

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2017	22,493	24,880
Winter 2017-18	21,727	22,884
Summer 2018	22,381	24,709

About 1,550 MW of new supply – 1,000 MW of gas, 500 MW of wind and 50 MW of hydroelectric – is expected to be connected to the province's transmission grid over the Outlook period. By the end of the period, the amount of grid-connected wind is expected to increase to about 4,500 MW and grid-connected solar is expected to remain at 380 MW.

By the end of the Outlook period, embedded wind capacity will exceed 600 MW and embedded solar will surpass 2,200 MW. Overall contracted embedded capacity will reach 3,200 MW over the Outlook horizon.

On August 21, 2017, a solar eclipse is expected to pass over parts of the continental U.S. and Canada. Although Ontario will see only 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. To effectively position Ontario for this event, the IESO will develop operating plans that may consider implementing pre-emptive control actions to maintain adequacy and reliability. These actions may include increasing the amount of flexible resources on-line, increasing reserves requirement, applying a higher margin to scheduled quantities of imports and exports and reviewing planned outage plans. The IESO will be working closely with market participants and interconnected Reliability Coordinators to ensure reliable operation before, during and after this celestial 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 will decline over the forecast horizon. This is partially due to embedded solar generation, which has reduced the size of the summer peak and pushed it to later in the day.
- Over the forecast period, energy demand growth should remain fairly flat with a slight decline in 2017 followed by a slight increase in 2018.

Resource Adequacy

- Under the **firm scenario**, with extreme weather conditions, the reserve is below the requirement for a total of 29 weeks over the summer periods; the largest shortfall is approximately 3,400 MW. If extreme weather materializes, planned generator outages may need to be rescheduled.
- For the **planned scenario**, with extreme weather conditions, the reserve is below requirement for a total of 20 weeks over the summer periods; the largest shortfall is around 3,300 MW.

Transmission Adequacy

Ontario's transmission system is expected to be able to reliably serve 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 and transmission 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 capacity for future load growth.
- High voltages in Eastern Ontario and the Greater Toronto Area (GTA) continue to present operational challenges. This can result from low transfer levels across the 500 kilovolt (kV) transmission system from Bowmanville SS to Hawthorne TS. The IESO and Hydro One are currently managing this situation with day-to-day operating procedures. To address this issue on a longer-term basis, the IESO requested Hydro One to install two 500 kV line-connected shunt reactors at Lennox TS with a target in-service date of Q4 2020.
- Occasionally, imports may be reduced in Eastern Ontario, typically for brief periods during the summer, due to the thermal limitations of the 230 kV Hawthorne-to-Merivale circuits, which are part of the transmission network path between Eastern Ontario and the major load centers near the GTA area. Transmission reinforcement on the Hawthorne-to-Merivale path is being considered.

- During peak load periods, the two under-sized autotransformers at Hawthorne TS are expected to be overloaded after a 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.
- The new Copeland TS is 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.
- The new Manby 230/115 kV Autotransformer Overload Protection scheme, with an in-service date of Q2 2018, will protect the autotransformer that remains in service following outages to the other two autotransformers at either the East or West yards at Manby TS.
- The new Bruce Remedial Action Scheme (RAS) will replace the existing Special Protection System in Q4 2017. The new scheme will increase operational flexibility by detecting and responding to a greater number of system contingencies.
- The new Clarington 500/230 kV transformer station near the GTA is expected to be in service by the end of Q1 2018. The station will improve the power system reliability of central and eastern GTA, especially after the retirement of Pickering Nuclear Generating Station (NGS).
- Hydro One is proceeding with construction of a new transformer station at Runnymede TS and upgrading the 115 kV circuits that serve Runnymede TS from Manby TS. With an in-service date of Q4 2018, this project will provide relief for the nearby existing load stations and additionally support the Eglinton Light Rail Transit project.

Operability

Conditions for surplus baseload generation (SBG) will continue over the Outlook period. However, the magnitude and the frequency of the SBG are reduced with the nuclear refurbishment program. 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 manoeuvres or shutdown.

The need for more flexible resources to respond to intra-hour differences between expected and actual variable generation production and expected and actual Ontario demand continues to be a priority. As the output from the variable generation fleet continues to rise, the need for flexible resources capable of responding to IESO dispatch signals and increasing their output within 30 minutes continues to increase. At times, to maintain reliability the IESO may take control actions such as, but not limited to, committing/constraining on dispatchable resources or manually adjusting the variable generation forecast. The IESO will engage with stakeholders to explore a range of potential solutions for enhanced flexibility in the electricity system. The IESO encourages all stakeholders in Ontario's electricity sector, or their representatives, with an interest in this initiative to participate in this stakeholder engagement.

In addition, 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 as needed between 2017 and 2019, as well as have sufficient market depth to schedule up to 250-300 MW of regulation capacity on an as-needed basis by the year 2020. The IESO issued a draft RFP for incremental regulation capacity on June 1, 2017. The final RFP is expected to be issued by end of June with a submission deadline of end of September 2017.

Caution and Disclaimer

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1 Introduction

This Outlook covers the 18-month period from July 2017 to December 2018 and supersedes the last Outlook released on March 21, 2017.

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/sector-participants/planning-and-forecasting/18-month-outlook.

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:

- Toll Free: 1-888-448-7777
- Tel: 905-403-6900
- Fax: 905-403-6921
- E-mail: customer.relations@ieso.ca.

- 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 2017. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for April and May 2017 has been included in the tables.

2.2 Updates to Resources

The 18-Month Outlook uses planned generator outages submitted by market participants to the IESO's outage management system as of May 12, 2017.

As of May 12, 2017, the following generators completed the market registration process since the last Outlook:

- Greenfield South (also known as Green Electron Power) – 334 MW (gas)
- Windsor Solar – 50 MW
- Southgate Solar – 50 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 outage management system as of April 24, 2017, were used.

2.4 Updates to Operability Outlook

The Outlook for surplus baseload generation (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 May 12, 2017.

- End of Section -

3 Demand Forecast

The IESO forecasts electricity demand on the IESO-controlled grid. This demand forecast covers the period July 2017 to December 2018 and supersedes the previous forecast released in March 2017. Tables of supporting information are contained in the 2017 Q2 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)
- 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.

Overall, grid-supplied energy demand is forecast to remain fairly flat over the forecast horizon. For 2017, the expectation is that energy demand will decrease as increased conservation savings and increased embedded generation output will exceed the increased demand stemming from economic and demographic growth. The economy still enjoys excellent fundamentals: a low dollar, strong U.S. growth, low interest rates and low inflation, which are helping the industrial sectors to push up energy demand in 2018.

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 more downward pressure from conservation than they do from embedded generation. Since the winter peaks occur after sundown, conservation effects such as 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)
Summer 2017	22,493	24,880
Winter 2017-18	21,727	22,884
Summer 2018	22,381	24,709
Year	**Normal Weather Energy (TWh)**	**% Growth in Energy**
2006	152.3	-1.9%
2007	151.6	-0.5%
2008	148.9	-1.8%
2009	140.4	-5.7%
2010	142.1	1.2%
2011	141.2	-0.6%
2012	141.3	0.1%
2013	140.5	-0.6%
2014	138.9	-1.1%
2015	136.2	-1.9%
2016	136.2	0.0%
2017 (Forecast)	135.4	-0.6%
2018 (Forecast)	136.4	0.7%

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

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's weather was colder than normal.
- The month's peak occurred on the third coldest day of the month as daytime highs reached -8.1°C (at Toronto) under gusty wind conditions. The two coldest days occurred on a weekend.
- The actual peak demand was 19,174 MW, with the weather-corrected value of 18,986 MW. These values are the lowest for March since market opening.

- Energy demand for the month was 11.6 TWh and 11.3 TWh weather-corrected. It is the lowest weather-corrected energy demand for March since market opening.
- The minimum demand for the month was 12,158 MW, which occurred in the early hours of Sunday, March 26.
- Embedded generation production for the month was 446 GWh, an increase of 0.8 percent over the previous March and was driven by gains in solar production. Declines in other embedded generation led to the small growth rate.
- Wholesale customers' consumption for the month increased by 1.7 percent compared to the previous March, ending two months of decline.

April

- The weather for April was milder than normal.
- The peak occurred on April 6, which was the second coldest day of the month. The actual peak was 17,349 MW (18,217 MW weather-corrected). Both values are the lowest for April since market opening.
- Energy demand for the month was 9.8 TWh (10.2 TWh weather-corrected). Once again, both represent the lowest April values since market opening. This month was the first time demand in any month has dropped below 10.0 TWh.
- The minimum demand was 10,167 MW and occurred in the early morning of Easter Sunday, April 16, which was a warm weekend. Due to the warm weather, the minimum was low by historical standards.
- Embedded generation, as reported by distributors, was 604 GWh for the month. This represents a 10.0-percent decrease compared to the previous April. The decline was attributable to a drastic reduction in non-contracted production (-61 percent). Contracted wind (42%) and solar (7%) production was up significantly.
- Wholesale customers' consumption was down 5.1 percent over the previous April. Part of this is attributable to the loss of one day to holiday – Good Friday occurred in March in 2016.

May

- The weather for May was milder than normal with the exception of the hottest or peak days, which were near normal. The actual peak for May was 17,738 MW, occurring on Thursday May 18, which was the warmest day of the month. The weather-corrected value was virtually the same (17,764 MW). It was the lowest actual May peak since the recession.
- The mild weather pushed actual demand to 10.2 TWh, which is the lowest May since market opening. Weather-corrected demand was a similar 10.1 TWh and represents an all-time low for the month.
- Minimum demand of 10,745 MW occurred Sunday, May 21 at 3 a.m. This was the Victoria Day long weekend. This value is consistent with May minimums since 2008.

- Embedded generation reported by distributors was 632 GWh for the month, a decrease of 7 percent over the previous May. Solar (-8%) and non-contracted generation (-59%) drove the decline. Wind was up significantly (71%) from the previous May.

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

2016-17 Spring Actuals

Overall, energy demand for the three months from March to May was down 2.0 percent compared with the same three months one year prior. After adjusting for the weather, demand for the three months showed a virtually identical decline of 1.9 percent.

Embedded generation for the spring was down 4 percent compared to the previous spring. Both solar and wind production was up, but was offset by declines in non-contracted generation.

For the three months, wholesale customers' consumption posted a 1.3-percent decline compared to the previous spring. Increases from motor vehicle manufacturing and iron & steel were offset by declines in the other major sectors.

The 2017 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

Though the economic fundamentals remain very favourable for Ontario – a low dollar, low inflation and low interest rates – a great deal of uncertainty exists with respect to the province's major trade partner. With the U.S. triggering North American Free Trade Agreement (NAFTA) renegotiation, there is some concern about the potential impact given Ontario's economic ties with America. The Comprehensive Economic and Trade Agreement and the revival of the Trans Pacific Partnership should help the province diversify its export markets in the long run but, in the near term, the impacts from NAFTA renegotiation would be more impactful.

Table 3.3.4 of the 2017 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.

Table 3.3.5 of the 2017 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 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 rates can factor into all weekdays throughout the year, and the size of the impact will be determined by the pricing structure. The ICI impacts demand beyond the five peak days as participants adjust their consumption based on projected values that are weather dependent. In 2017 two changes were made to the program that will increase the number of participants. First, the restrictions on loads greater than 1 MW were removed, allowing businesses from the commercial sector (hospitals, universities, hotels etc.) to participate. Secondly, the program was expanded to market participants in the manufacturing and greenhouse sector with an average peak load greater than 500 kW. The ICI program is estimated to have reduced peak demand by about 1,300 MW in the summer of 2016.

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.

Demand measures – 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. Demand reductions due to these programs are added back to the actual demand, and the forecast is based on demand prior to the impacts 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 May 12, 2017

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	10,622	5	0	0
Hydroelectric	8,451	5,803	73	0	0
Gas/Oil	10,277	7,812	31	334	1
Wind	3,983	533	35	0	0
Biofuel	495	449	9	0	0
Solar	380	38	8	100	2
Total	**36,563**	**25,228**	**161**	**434**	**3**

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 information is current as of May 12, 2017. 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)	Capacity Considered Planned (MW)
Niagara Region Wind Farm	West Lincoln NRWF	Southwest	Wind		Commercial Operation	230	230
Namewaminikan Hydro		Northwest	Water	2017-Q2	Commissioning	0	10
Peter Sutherland Senior Generating Station		Northeast	Water	2017-Q2	Commissioning	0	28
Harmon Unit 2 Runner Upgrade		Northeast	Water	2017-Q2	Commissioning	0	10
Harmon Unit 1 Runner Upgrade		Northeast	Water	2017-Q3	Commissioning	0	10
Belle River Wind		West	Wind	2017-Q4	Under Development	0	100
Kapuskasing Generating Station		Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
North Bay Generating Station		Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
Napanee Generating Station		East	Gas	2018-Q1	Under Development	0	985
North Kent Wind 1		West	Wind	2018-Q1	Under Development	0	100
Amherst Island Wind		East	Wind	2018-Q2	Under Development	0	75
Total						**110**	**1,429**

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 output data, they are also included in the planned scenario for the rest of the Outlook period, too.

4.1.2 Generation Capability

Hydroelectric

A monthly forecast of 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	6,008	5,864	5,795	5,843	5,653	5,633	5,319	5,068	5,383	5,699	6,099

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%	33.7%	33.2%	22.0%	12.6%	12.6%	12.6%	16.2%	30.8%	35.8%	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.

It should be noted that due to the increasing penetration of embedded solar generation, the grid demand profile has been changing, with summer peaks being pushed later in the day. As a consequence, the contribution of grid-connected solar resources at the time of peak Ontario demand has declined.

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 procured through an annual Demand Response Auction held in December 2017 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 impacts of actual activations of demand measure are added back into the demand history prior to forecasting demand for future periods.

The second annual DR auction held in December 2016 procured 455.2 MW for the summer six-month commitment period beginning on May 1, 2017, and 477.5 MW for the winter six-month commitment period beginning on November 1, 2017. The DR capacity acquired through the DR auction is reflected in the Outlook.

4.1.4 Firm Transactions

As part of the electricity trade agreement between Ontario and Quebec, 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 emissions in Ontario. The agreement includes the opportunity to cycle energy.

The capacities cleared in the New York Independent System Operator (NYISO) capacity auctions for summer months by Ontario generators are posted at the NYISO website. NYISO will receive a total of 90 MW from July to August and 127 MW from September to October 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)	36,563	
New Generation and Capacity Changes (MW)	1,429	110

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. 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. Submitted generator planned outages are reflected in both scenarios. 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 2017		Winter Peak 2018		Summer Peak 2018	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,793	36,841	36,673	36,832	36,673	37,992
2	Total Reductions in Resources (MW)	11,784	11,807	8,680	8,647	10,208	10,410
3	Demand Measures (MW)	767	767	759	759	771	771
4	Firm Imports (+) / Exports (-) (MW)	-90	-90	-500	-500	0	0
5	Available Resources (MW)	25,686	25,712	28,252	28,444	27,236	28,353

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

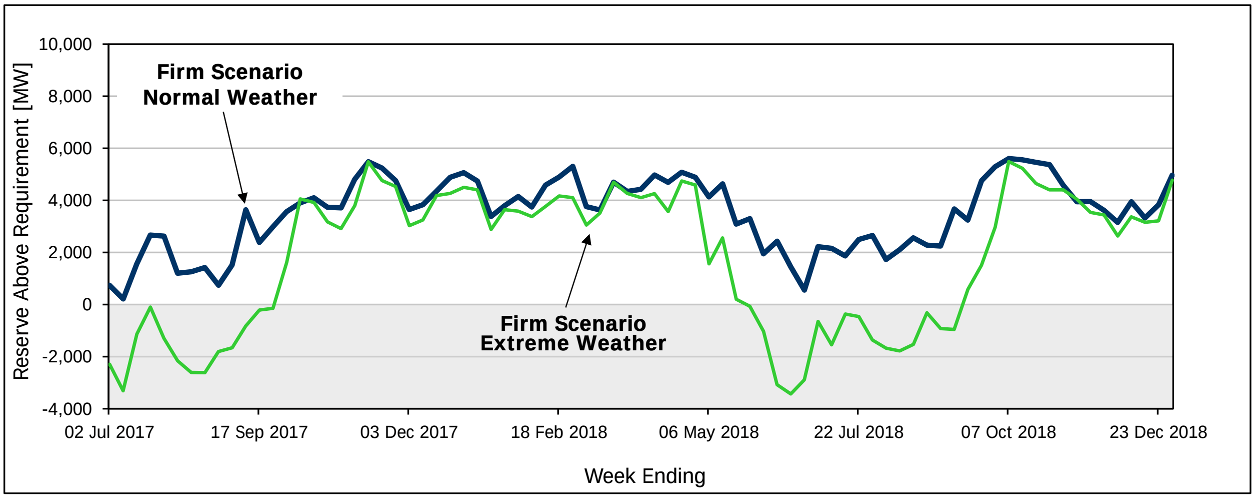
The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages and have been assessed as of April 24, 2017. The generation planned outages occurring during this Outlook period have been assessed as of May 12, 2017.

4.2.1 Firm Scenario with Normal and Extreme Weather

The **firm scenario** incorporates all existing capacity plus approximately 230 MW of wind capacity that had achieved commercial operation status as of May 12, 2017.

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 29 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 periods. Therefore, generators expected to perform maintenance on their units during the summer should understand that those outages are at risk and are advised to review their planned maintenance plans and consider rescheduling them if they are critical for the continued operation of the units.

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

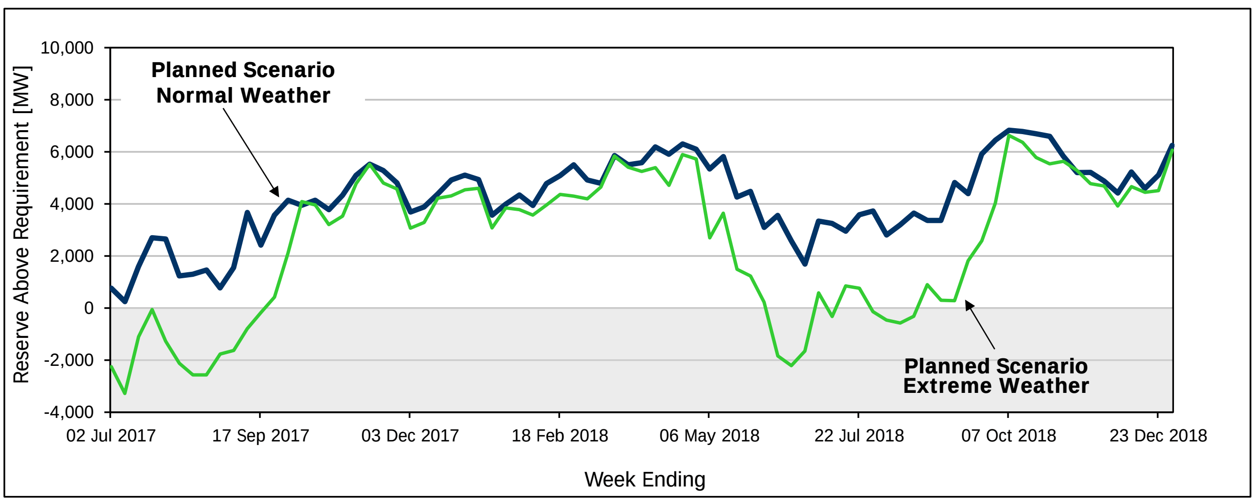


4.2.2 Planned Scenario with Normal and Extreme Weather

The **planned scenario** incorporates all existing capacity plus all capacity coming in service. Approximately 1,550 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 a total of 20 weeks during the 18-Month Outlook timeframe under extreme weather conditions. This shortfall is largely attributed to the planned outages scheduled for those weeks.

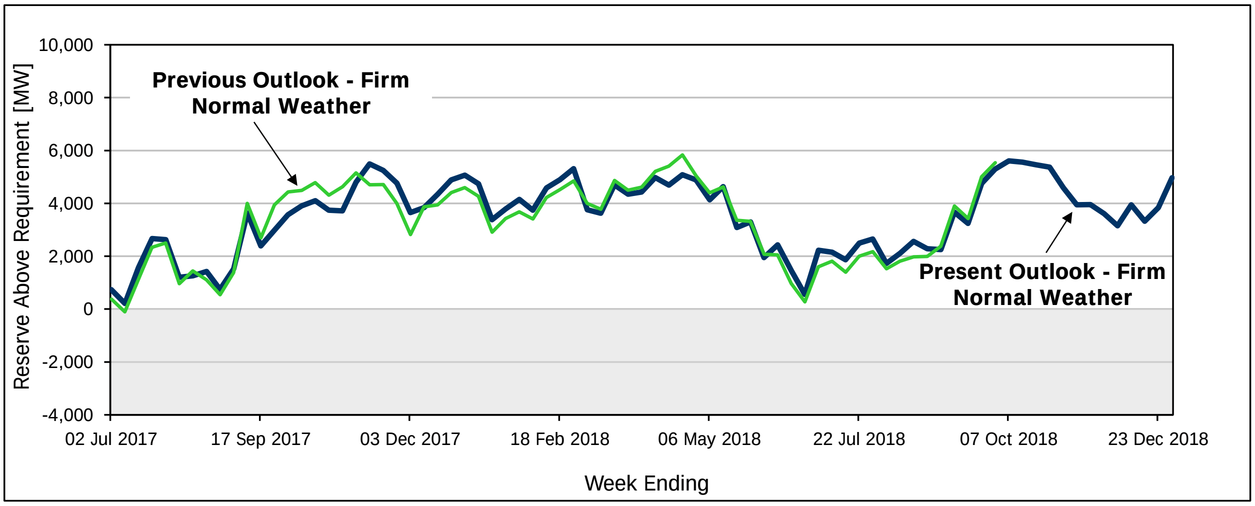
Figure 4.2: Normal vs. Extreme Weather: Planned Scenario RAR



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 21, 2017. The difference is mainly due to changes in planned outages.

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 assessment. 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 2017 Q2 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 Outlook 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	**207.5**	**15,749**	**207.5**	**15,749**	**0.0**	**451.8**	**580.8**
Bruce	1.0	74	70.9	5,382	69.9	1.2	155.2
East	12.6	956	15.8	1,198	3.2	25.3	60.7
Essa	11.9	901	3.7	279	-8.2	24.8	14.9
Niagara	6.2	472	19.7	1,498	13.5	14.6	42.2
Northeast	14.4	1,095	14.6	1,105	0.2	24.3	32.9
Northwest	5.8	441	5.5	416	-0.3	10.0	20.6
Ottawa	14.3	1,085	0.0	3	-14.3	26.1	2.4
Southwest	42.8	3,249	6.2	473	-36.6	94.3	27.1
Toronto	78.2	5,933	61.6	4,672	-16.6	183.2	143.9
West	20.3	1,543	9.5	723	-10.8	48.0	80.9

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 – July 1, 2017, to Dec. 31, 2018

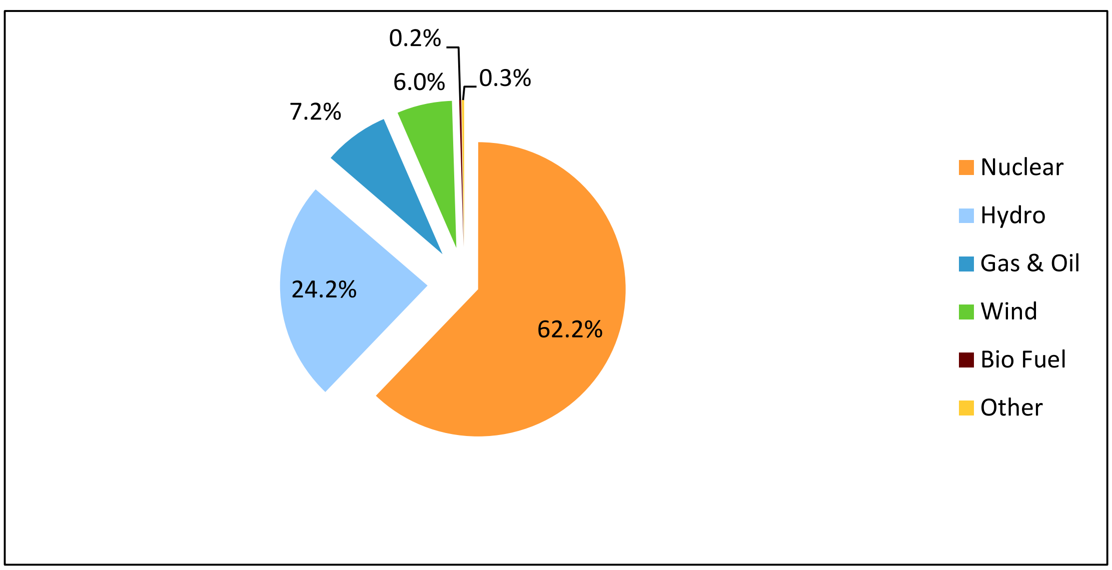


Figure 4.5: Monthly Production by Fuel Type – Jul. 1, 2017, to Dec. 31, 2018

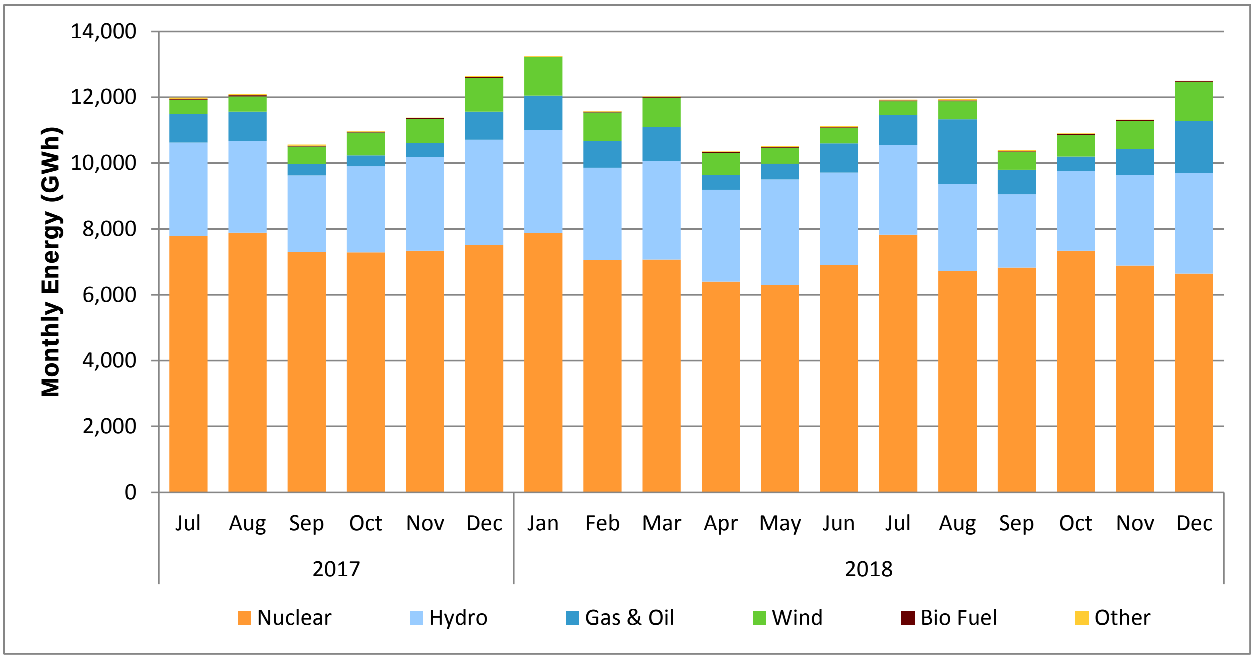


Table 4.9: Firm Scenario - Normal Weather: Ontario Energy Production by Fuel Type

Fuel Type (Grid Connected)	2017 (July 1 - Dec 31) (GWh)	2018 (Jan 1 - Dec 31) (GWh)	Total (GWh)
Nuclear	45,106	83,867	128,973
Hydro	16,603	33,552	50,155
Gas & Oil	3,735	11,121	14,856
Wind	3,837	8,690	12,526
Bio Fuel	176	299	475
Other (Solar & DR)	211	309	521
Total	**69,668**	**137,838**	**207,507**

4.4 Outage Assessment Methodology

The adequacy assessment methods are continually being refined to reflect the evolving system conditions. The IESO recently made the following changes to the assumptions used for adequacy assessments:

- adjusted the maximum continuous rating values for temperature dependent thermal units
- modelled forced outage rates more accurately
- reduced the hydroelectric capability under extreme weather conditions to better reflect observed performance.

The first two changes contributed to the reduction in resources available under normal weather conditions. The last change further reduced the resources available under extreme weather conditions.

In the past, outage approvals were given between three days and two weeks prior to the scheduled start time of the outage. The outage assessment process changed to a quarterly process in Q4 2016, allowing advance approval up to eight months prior to the start. The IESO will initiate a stakeholder engagement later this year to discuss the current outage assessment methodology and to solicit feedback on proposed changes to align this with the changes to the outage approval process.

- 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 Outlook period. A list of such projects is provided in Appendix B. Only transmission and load-serving projects that are either major modifications or significantly improve reliability are included. Projects that are already in service or whose completion is planned beyond the period of this Outlook, or that are minor transmission equipment replacements or refurbishments, are not shown.

Some areas have experienced load growth to warrant additional investments in new load-serving stations and reinforcements of local area transmission. Several local area transmission 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 capacity to serve 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 April 24, 2017.

5.2 Transmission System Adequacy

The IESO assesses transmission adequacy using the methodology based on conformance to established criteria including the Ontario Resource and Transmission Assessment Criteria (ORTAC), NERC transmission planning standard TPL 001-4 and NPCC Directory #1 as applicable. Planned system enhancements and known transmission outages are also considered for the studies. Zonal assessments are presented in the following sections. Overall, the Ontario transmission system is capable of serving the demand under the normal and extreme conditions forecast for the Outlook period.

In some areas in the province, existing transmission infrastructure as described below, have been identified as either currently having or anticipated to have some limitations to serve 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/get-involved/regional-planning.

5.2.1 Toronto and Surrounding Area

The load-serving capability to the GTA is expected to be adequate to meet the forecast demand through to the end of this 18-month Outlook 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. During peak load periods, this could potentially overload the remaining autotransformer. 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 one of the three autotransformers be forced out of service while another 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 load-serving capacity in the area and will also enable the refurbishment of the facilities at John TS.

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 come 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.

In the eastern portion of the GTA, a new 500/230 kV transformer station named Clarington TS is expected to be in service by the end of Q1 2018. Clarington TS provides a new 230 kV serving point and improves the customers' service reliability for Pickering, Ajax, Whitby, Oshawa and Clarington areas. Also, Clarington TS is critical in maintaining the service reliability of central and eastern GTA, by relieving the 500/230 kV transformers at Cherrywood TS, which could be overloaded when Pickering NGS retires.

As was recommended in the Central Toronto IRRP, Hydro One is proceeding with construction of a new transformer station at Runnymede TS and upgrading the 115 kV circuits that serve Runnymede TS from Manby TS. This project, planned to be in service by Q4 2018, will provide relief for the existing Runnymede TS and nearby Fairbank TS, which are at capacity to serve the peak demand in the area. In addition, it will serve the new Eglinton Light Rail Transit project that is currently under construction.

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

Occasionally, imports may be reduced in Eastern Ontario, typically for brief periods during the summer, due to the thermal limitations of the 230 kV Hawthorne-to-Merivale circuits, which are part of the transmission network path between Eastern Ontario and the major load centers near the GTA area. Reinforcement on the Hawthorne-to-Merivale path is being considered.

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.

High voltages in Eastern Ontario and the GTA continue to present operational challenges. This can result from low transfer levels across the 500 kV transmission system from Bowmanville SS to Hawthorne TS. Temporary removal from service of at least one of the 500 kV circuits in Eastern Ontario continues to be required during those periods. The IESO and Hydro One are currently managing this situation with day-to-day operating procedures. To address this issue on a longer-term basis, the IESO requested Hydro One to install two 500 kV line-connected shunt reactors at Lennox TS with a target in-service date of Q4 2020.

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.

As per the near-term plan in the Windsor-Essex Region IRRP, Hydro One continues to proceed with the Supply to Essex County Transmission Reinforcement (SECTR) project, which consists of the new 230 kV Leamington TS along with a new double-circuit connection line. This project, when completed in Q2 2018, will address the region's service capacity and restoration needs, while leveraging the refurbishment of the end-of-life assets at the nearby Kingsville TS.

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 now expected to be complete in Q3 2019.

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 Hunta and Kapuskasing to be exceeded. To ensure that the existing level of service 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 part of these constraints. This project is currently scheduled to be in service by 2020. However, additional constraints in the Sault Ste. Marie and Sudbury areas will continue to limit generation in Northwestern Ontario.

Transmission constraints are also restricting the connection of additional load in some areas in northwestern Ontario. Some of these restrictions will be addressed by the proposed 230 kV single-circuit line to Pickle Lake, which is currently scheduled to be in service in early 2020. The IESO has completed IRRPs for Northwest Ontario, which identify plans to address other load connection constraints. 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 originally anticipated to become operational in the latter part of 2016 have revised their implementation schedules while navigating a number of unanticipated project development issues. Revised completion dates now extend into the latter part of 2017.

6.2 Surplus Baseload Generation

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 that include inter-tie 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 2016 to the end of March 2017. The lower demand, 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 spring of 2016.

Figure 6.1 MWh Curtailments versus Ontario Demand

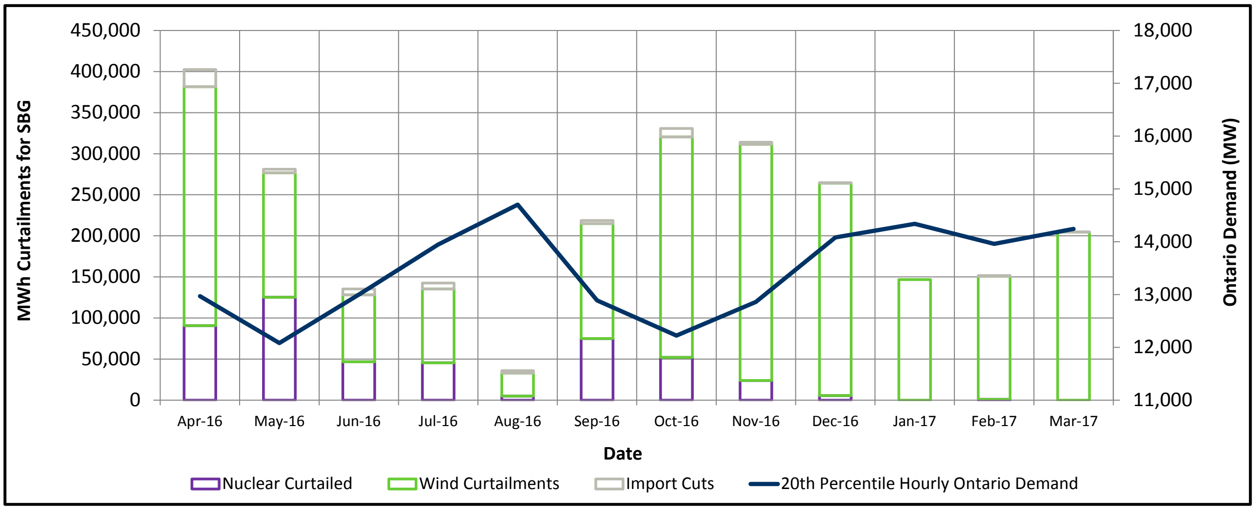
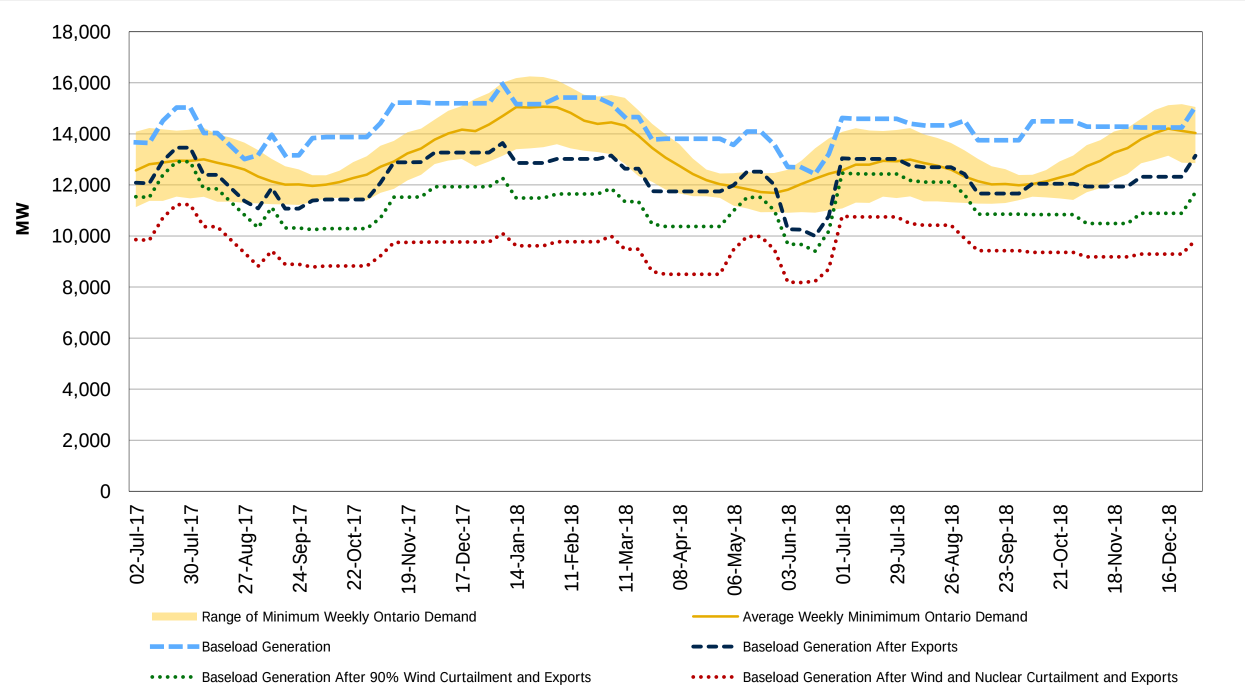


Figure 6.2 shows the forecast SBG for the next 18 months and the flexibility from nuclear, wind and solar generation and exports.

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 expected exports and run-of-river hydroelectric production, the latest planned outage information and in-service dates for new or refurbished generation. The expected contribution from self-scheduling and intermittent generation has also been updated to reflect the latest data. The information on the dispatch order of wind, solar and flexible nuclear resources can be found in Market Manual 4 Part 4.2. 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, 2017. 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)	35.3%	35.3%	33.2%	34.6%	24.8%	14.5%	14.5%	14.5%	20.0%	30.0%	36.0%	35.3%

6.3 Operability Assessment

- The need for more flexible resources to respond to intra-hour differences between expected and actual variable generation production and expected and actual Ontario demand continues to be a priority. As the output from the variable generation fleet continues to rise, the need for flexible resources capable of responding to IESO dispatch signals and increasing their output within 30 minutes continues to increase. At times, to maintain reliability, the IESO may take control actions such as, but not limited to, committing/constraining on dispatchable resources or manually adjusting the variable generation forecast. The IESO will engage with stakeholders to explore a range of potential solutions for enhanced flexibility in the electricity system. The IESO encourages all stakeholders in Ontario's electricity sector, or their representatives, with an interest in this initiative to participate in this stakeholder engagement.

- Significant energy price spikes have been observed in the last few shoulder seasons, but especially this spring, reflecting the need for and value of resources that can provide flexibility through an ability to respond to short-term supply-demand imbalances.
- 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 as needed between 2017 and 2019, and have sufficient market depth to schedule up to 250-300 MW of regulation capacity on an as-needed basis by the year 2020. The IESO issued a draft RFP for incremental regulation capacity on June 1, 2017. The final RFP is expected to be issued by end of June with a submission deadline of end of September 2017.
- On August 21, 2017, a solar eclipse is expected to pass over parts of the continental U.S. and Canada. Although Ontario will see only 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. To effectively position Ontario for this event, the IESO will develop operating plans that may consider implementing pre-emptive control actions to maintain adequacy and reliability. These actions may include increasing the amount of flexible resources on-line, increasing reserves requirement, applying a higher margin to scheduled quantities of imports and exports and reviewing planned outage plans. The IESO will be working closely with market participants and interconnected Reliability Coordinators to ensure reliable operation before, during and after this celestial event.

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Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca
@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/ieso

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