18-Month Outlook

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

FROM OCTOBER 2018 TO MARCH 2020

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Executive Summary

Reliability Outlook

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 are below requirement, without reliance on imports, for thirteen weeks throughout summer 2019, in the firm scenario. Generators expecting to perform maintenance during the summer are advised to review their plans and consider rescheduling their outages, taking into consideration that the IESO's outage management criterion for adequacy assumes at most 2, 000 MW of imports. In summer 2018, the IESO experienced significant hot weather, causing the IESO to publish system advisory notices related to extreme temperature on at least nine days. In late June and early July, Ontario peak demand exceeded the 18-Month Outlook normal weather forecast on several occasions. Lower water conditions, particularly in northeastern Ontario, created resource availability challenges in addition to higher demand. To maintain reliability under these conditions, IESO actions can include committing additional generation and rejecting or revoking planned outages.

Demand Forecast

Over the forecast, peak demands will continue to face downward pressure from savings achieved through energy efficiency, embedded generation output and the Industrial Conservation Initiative (ICI).

After a significant decline in 2017, energy demand has been trending up over the first part of 2018. Demand is expected to rise in 2018, as stronger economic growth in the industrial sector will result in increased electricity consumption. At the same time, growth in embedded generation capacity has plateaued, reducing one of the major offsets to demand increases. The following table summarizes the forecasted seasonal peak demands over the next 18 months.

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2018-19	21,334	22,261
Summer 2019	22,068	24,485
Winter 2019-20	21,251	22,173

Supply

About 1,470 MW of new supply – 985 MW of gas, 375 MW of wind, 100 MW of solar and 15 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 and grid-connected solar is expected to increase to approximately 4,800 MW and500 MW respectively.

By the end of the Outlook period, embedded wind capacity will be about 600 MW and embedded solar will be about 2,200 MW. Overall contracted embedded capacity will be about 3,500 MW by the end of Outlook horizon.

Transmission Adequacy

Ontario's transmission system is expected to continue to reliably serve Ontario's 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 underway will be placed in-service during this timeframe. These projects, shown in Appendix B, will help relieve loading of existing transmission stations and provide additional capacity for future load growth.

Concurrent planned outages will continue to cause transmission limitations on the Flow East toward Toronto (FETT) interface during this forecast period. Outages submitted for generation resources located east of the FETT interface and/or transmission elements that impact the FETT interface may be placed at risk. Market participants should expect that these limitations will persist while Ontario's nuclear fleet is being refurbished.

Imports and exports may be reduced between New York and Ontario due to a long-term interconnection equipment outage at St. Lawrence. Efforts are underway to manage this outage and to consider longer-term solutions.

Operability

Conditions that may result in periods of surplus baseload generation are projected to continue over the Outlook period and will be managed effectively through existing market mechanisms, including intertie scheduling, the dispatch of grid-connected renewable resources and nuclear manoeuvres or shutdowns.

Outage Management

Changes to the IESO's adequacy criterion that feeds the outage management process are effective for outage plans occurring from May 2019 onward. This criterion uses extreme weather instead of normal weather conditions and assumes up to 2,000 MW of imports are available in determining if there is sufficient reserve above requirement. Participants are advised to refer to the extreme weather resource adequacy scenario to plan their outages beginning in summer 2019.

Changes to the 18-Month Outlook

Starting in December 2018, the IESO will be including an additional chapter in the 18-Month Outlook to give participants a 60-month (five-year) view of resource adequacy. This chapter will be published twice a year – prior to winter and summer – to provide information beneficial for outage scheduling. The IESO understands that many drivers (e.g., multiple nuclear refurbishment outages, changing transmission flow patterns and generation facilities reaching end- of-contract term) will make outage coordination and assessments more complex in the future. Access to a longer- term view will help all parties coordinate planned maintenance outages in advance.

Technical Planning Conference

On September 13, 2018, the IESO held its first Technical Planning Conference. Sector participants learned about the current electricity planning outlook, and how electricity planning processes and products will evolve as Ontario moves toward a more competitive electricity market. The updated planning outlook is intended to facilitate development of the incremental capacity auction – one of four initiatives that comprise the market renewal program – and future changes to the market. The IESO intends to provide regular projections of electricity supply, considering capacity needs, energy needs and other reliability services. At the conference, the attendees also learned about transmission planning and the competitive transmission procurement process currently under development. In addition to the feedback received during the Technical Planning Conference, stakeholders are encouraged to provide written feedback through the conference webpage.

Caution and Disclaimer

The contents of these materials are for discussion and information purposes and are provided "as is" without representation or warranty of any kind, including without limitation, accuracy, completeness or fitness for any particular purpose. The Independent Electricity System Operator (IESO) assumes no responsibility for the consequences of any errors or omissions. The IESO may revise these materials at any time in its sole discretion without notice. Although every effort will be made by the IESO to update these materials to incorporate any such revisions, it is up to you to ensure you are using the most recent version.

Table of Contents

List of Tables

List of Figures

1 Introduction

This Outlook covers the 18-month period from October 2018 to March 2020 and supersedes the last Outlook released on June 20, 2018.

The purpose of the 18-Month Outlook is to:

- Advise market participants of the resource and transmission reliability of the Ontario electricity system
- Assess potentially adverse conditions that might be avoided through adjustment or coordination of maintenance plans for generation and transmission equipment
- Report on initiatives being implemented to improve reliability within the timeframe of this Outlook.

Additional supporting documents are located on the 18-Month Outlook section of the IESO website.

This Outlook presents an assessment of resource and transmission adequacy based on the stated assumptions, using the described methodology. Due to uncertainties associated with various input assumptions, readers 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 by:

- Telephone: 1-888-448-7777 or 905-403-6900
- Fax: 905-403-6921
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- End of Section -

2 Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast used in this Outlook is based on actual demand, weather and economic data through to the end of June 2018. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for July and August has also 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.

On July 27, 2018, OPG announced the closure of Thunder Bay GS and its contract was terminated on June 30, 2018. This change is taken into account in the estimates of available capacity in this report.

2.3 Updates to Transmission Outlook

Transmission outage plans that were submitted to the IESO's outage management system by August 3, 2018, were used for this Outlook.

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 August 24, 2018.

- 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 October 2018 to March 2020 and supersedes the previous forecast released in June 2018. Tables of supporting information are contained in the 2018 Q3 Outlook Tables spreadsheet.

Electricity demand is shaped by many factors with differing and/or competing 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 (energy efficiency and embedded generation) and those that shift demand (time- of-use rates and the Industrial Conservation Initiative [ICI]). The extent to which 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 has been fairly flat since the 2009 recession with small increases and decreases year-to-year; however, demand dropped significantly in 2017. The decline was fairly widespread across all regions of the province and sectors of the economy. Since the start of 2018, demand has experienced a rebound from the lows of 2017. The forecast is expected to see this continue throughout the remainder of 2018 as a strong U.S. economy and a low Canadian dollar continue to foster increased demand due to increased economic activity. Combined with population growth, this economic induced growth will exceed the reductions stemming from increased energy-efficiency savings. Embedded generation output also reduces the need for grid-supplied electricity, but the rate of growth in embedded output is declining as the rate of capacity additions slows. In 2019 demand growth is expected to slow and start the return to a flat trajectory.

Peak demands are subject to the same forces as energy demand, though the impacts vary. This is true when comparing energy versus peak demand and when comparing summer and winter peaks. Summer peaks are significantly affected by the growth in embedded generation capacity and pricing impacts (ICI and time-of-use rates). The majority of embedded generation is provided from solar-powered facilities that have high output levels during the summer peak period and low output during the winter peak periods. In addition to reducing summer peaks, increased embedded solar output is pushing the peak to later in the day. As such, peak demands will show a small decline over the forecast horizon.

Table 3.1 shows the historical and forecast annual energy demand and the forecasted seasonal peaks. Table 3.2 shows the weekly peaks and energy demand over the forecast horizon of the Outlook.

Table 3.1: Historical and Forecast Summary

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2018-19	21,334	22,261
Summer 2019	22,068	24,485
Winter 2019-20	21,251	22,173
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	132.3	-2.8%
2018 (Forecast)	135.1	2.1%
2019 (Forecast)	134.7	-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)
07-Oct-18	17,335	17,529	786	2,391					
14-Oct-18	17,170	17,542	507	2,373	14-Jul-19	21,665	23,368	838	2,708
21-Oct-18	17,374	17,938	392	2,416	21-Jul-19	21,142	23,375	1,035	2,603
28-Oct-18	17,502	18,189	318	2,458	28-Jul-19	21,232	24,033	841	2,680
04-Nov-18	17,788	18,560	416	2,472	04-Aug-19	21,852	24,380	958	2,706
11-Nov-18	18,774	19,475	601	2,578	11-Aug-19	21,550	24,237	985	2,677
18-Nov-18	19,044	19,927	342	2,589	18-Aug-19	20,731	23,838	1,362	2,653
25-Nov-18	19,437	20,324	607	2,658	25-Aug-19	20,783	22,840	1,413	2,638
02-Dec-18	19,828	20,998	409	2,703	01-Sep-19	20,060	22,545	1,370	2,534
09-Dec-18	19,942	21,258	555	2,729	08-Sep-19	18,529	21,827	680	2,382
16-Dec-18	20,503	21,513	690	2,780	15-Sep-19	18,937	20,626	781	2,449
23-Dec-18	20,293	21,464	362	2,768	22-Sep-19	17,618	19,588	420	2,420
30-Dec-18	19,184	19,894	528	2,646	29-Sep-19	16,979	18,274	554	2,359
06-Jan-19	20,890	22,203	570	2,810	06-Oct-19	17,248	17,182	786	2,401
13-Jan-19	21,334	22,261	547	2,873	13-Oct-19	17,095	17,215	507	2,428
20-Jan-19	20,969	21,599	483	2,862	20-Oct-19	17,278	17,794	392	2,379
27-Jan-19	20,686	21,783	404	2,868	27-Oct-19	17,418	18,050	318	2,467
03-Feb-19	20,735	21,927	734	2,881	03-Nov-19	17,686	18,419	416	2,485
10-Feb-19	19,981	21,510	635	2,815	10-Nov-19	18,648	19,305	601	2,586
17-Feb-19	19,734	21,214	581	2,768	17-Nov-19	18,927	19,761	342	2,595
24-Feb-19	19,388	21,215	501	2,713	24-Nov-19	19,320	20,153	607	2,665
03-Mar-19	20,016	21,282	531	2,749	01-Dec-19	19,713	20,836	409	2,707
10-Mar-19	19,474	20,396	649	2,702	08-Dec-19	19,804	21,077	555	2,736
17-Mar-19	18,349	19,140	611	2,618	15-Dec-19	20,402	21,361	690	2,791
24-Mar-19	18,018	18,755	569	2,532	22-Dec-19	20,218	21,337	362	2,779
31-Mar-19	17,909	18,928	567	2,531	29-Dec-19	19,077	19,541	528	2,655
07-Apr-19	17,590	18,182	471	2,466	05-Jan-20	19,752	21,231	570	2,731
14-Apr-19	16,820	17,810	496	2,401	12-Jan-20	21,251	22,173	547	2,868
21-Apr-19	16,405	16,696	531	2,322	19-Jan-20	20,742	21,354	483	2,828
28-Apr-19	16,362	16,512	721	2,327	26-Jan-20	20,467	21,572	404	2,835
05-May-19	17,484	19,912	849	2,309	02-Feb-20	20,523	21,720	734	2,861
12-May-19	16,657	19,413	845	2,326	09-Feb-20	19,829	21,372	635	2,789
19-May-19	18,222	21,526	1,175	2,352	16-Feb-20	19,363	20,842	581	2,728
26-May-19	17,961	21,691	1,330	2,293	23-Feb-20	19,474	21,216	501	2,702
02-Jun-19	18,643	21,222	1,292	2,367	01-Mar-20	19,721	20,992	531	2,735
09-Jun-19	19,364	23,689	1,055	2,516	08-Mar-20	19,375	20,294	649	2,682
16-Jun-19	20,202	23,670	835	2,529	15-Mar-20	18,152	18,939	611	2,587
23-Jun-19	21,363	23,932	754	2,596	22-Mar-20	17,779	18,518	569	2,503
30-Jun-19	21,556	23,534	1,016	2,629	29-Mar-20	17,697	18,714	567	2,503
07-Jul-19	22,068	24,485	814	2,629	05-Apr-20	17,459	18,061	471	2,460

3.1 Actual Weather and Demand

Since the last forecast, the actual demand and weather data for June, July and August 2018 have been recorded. It is interesting to note that for the third consecutive year the annual peak has occurred during a heat wave in September.

June

- June's weather was slightly above normal on average as the month started out mild before heating up into the Canada Day long weekend. Temperatures later in the month were significantly above normal, but peaks were blunted by the two hottest days occurring on weekends.

- The June peak occurred on Monday June 18, the fourth hottest day of the month following a very hot weekend. While consistent with the numbers recorded over the last several years, at 21,369 MW this year's June peak was unusual, as it occurred early in the day as a storm rolled across the province, bringing a cold front and breaking the heat wave. The afternoon high was 31°C (at Toronto), but by that time the weather had already turned cooler. Since the peak occurred earlier in the day, it was subject to significantly greater downward pressure both from embedded solar and ICI customers actively reducing their load at the time of the peak.
- The weather-corrected peak was 20,502 MW, which is consistent with June weather-corrected peaks from 2015 and 2017.
- Energy demand for the month was 10.9 TWh (10.9 TWh weather corrected), which is an increase over June 2017.
- The minimum demand for the month was 10,698 MW which is in line with recent June values since the last recession. The minimum occurred in the early hours of Sunday June 10.
- Embedded generation for the month was 601 GWh, an increase of 4.2% compared to the previous June. Solar output accounted for the increase as all other fuel types were down compared to June 2017.
- Wholesale customers' consumption rose 2.3% over June 2017 and represented the largest monthly gain in over two years. Big increases in the mining sector (14.8%) and petroleum (7.0%) more than offset declines in iron and steel (-5.2%) and the automotive sector (-1.7%).

July

- The weather for July was consistently warmer than normal across the month. The month started on a heat wave over the Canada Day weekend.
- While the hottest days of the month occurred during the holiday weekend, the peak of 23,046 MW (22,244 MW weather corrected) was recorded on July 5, which was the fourth hottest day of the month with the humidex topping 40°C. ICI actions reduced demand on the peak day. Since July was above normal ICI actions occurred on seven days throughout the month.
- Energy demand for the month was 12.7 TWh (12.3 TWh weather corrected). Both of these values are the highest since July 2013.
- The minimum for the month was 11,413 MW and occurred in the early morning hours of Sunday July 8, after the heat wave had ended.
- Embedded generation for the month topped 516 GWh, which represents an 11.2% decrease compared to the previous July. Solar output was up, but all other fuel types were down.
- After four months of positive growth, wholesale customers' load had a reversal in July dropping by 1.2% compared to the previous July. The reductions were fairly broad based.

August

- The weather for August was hotter than normal, with average temperatures for the month making it the second hottest August in forty years. Peak temperatures, while above normal, were not record highs.
- The August peak was recorded on the third hottest day of the month, as the two hottest days occurred over the Civic Holiday long weekend. Peak demand for the month was 21,990 MW (21,274 MW weather corrected). ICI actions occurred on this day, as well as on two others in the month.
- Energy demand for the month was 12.7 TWh (12.2 TWh weather corrected). Both are increases over the previous August.
- While minimums usually occur on weekends or holidays, the lowest demand in August was 11,966 MW and occurred during the early morning hours of Thursday, August 23.The 23rd was one of the mildest days of the month which led to lower air conditioning use and a monthly minimum.
- Embedded generation for the month topped 530 GWh, which represents a 5.0% decrease compared to the previous August. Solar (14%) and wind (6%) output was up, but all other fuel types were down.
- After a step back in July, wholesale customers' load grew by 2.3% compared to the previous August. Other than mining, all major sectors showed growth over the previous August.

Overall, energy demand for the three summer months from June to August was up 8.0% year over year. After adjusting for the weather, demand for the three months showed an increase of 4.4%.

Embedded generation for the three months was down 4.0% compared to the previous summer. Solar output was up (18%) but all other fuel types were lower.

For the three months, wholesale customers' posted a 1.1% increase in consumption over the same months in 2017. Motor vehicle manufacturing (7.1%), petrochemicals (6.1%) and mining (3.9%) drove industrial growth for the three months.

The 2018 Q3 Outlook Tables spreadsheet contains 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

The overall economic environment remains quite positive for Ontario. Strong U.S. growth, a lower Canadian dollar and low interest rates are conducive to growth in the province's export-oriented energy-intensive manufacturing sector. However, uncertainty persists as a result of potential adjustments to tariffs, Bank of Canada interest rate decisions, and changes in trade policy. Barring these risks, Ontario should see increasing economic output throughout 2018 and 2019. Table 3.3.4 of the 2018 Q3 Outlook Tables presents the economic assumptions for the demand forecast.

3.2.2 Weather Scenarios

To produce demand forecasts, the IESO uses weather scenarios that include normal and extreme weather, along with a measure of uncertainty in demand due to weather volatility, otherwise known as "load forecast uncertainty."

Table 3.3.5 of the 2018 Q3 Outlook Tables presents the weekly weather data for the forecast period.

3.2.3 Pricing, Conservation and Embedded Generation

Both demand measures and load modifiers can affect demand but they differ in how they are treated within the Outlook. Demand measures are not incorporated into the demand forecast and are instead treated as resources. Load modifiers are incorporated into the demand forecast.

Demand measures are dispatched like a generation resource and are, therefore, included in the supply mix. Demand measures are added back into the history when forecasting demand. Therefore, the demand forecast is prior to the impacts of demand measures.

Load modifiers include energy efficiency (energy-efficiency programs, codes and standards and fuel switching), price impacts (time of use and Industrial Conservation Initiative) and embedded generation. The load modifiers are incorporated into the demand forecast. Each impacts demand differently – in terms of level and timing – but all have the net effect of reducing the amount of grid-supplied electricity. Energy efficiency impacts both peaks and energy, prices reduce demand during peak periods and embedded generation impacts vary by fuel type.

- End of Section -

4 Resource Adequacy Assessment

This section provides an assessment of the adequacy of resources to meet the forecast demand. Resource adequacy is one of the reliability considerations used for approving outages. 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, when reserves are above required levels, additional outages can be contemplated, provided other factors, such as local considerations, operability or transmission security, do not pose a reliability concern. In those cases, the IESO may place an outage at risk signaling to the facility owner to consider rescheduling the outage.

The existing installed generation capacity is summarized in Table 4.1. This includes capacity from new projects that have completed 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 August 24, 2018

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Outlook Peak (MW)	Number of Stations	Change in Installed Capacity (MW)	Change in Stations
Nuclear	13,009	11,537	5	0	0
Hydroelectric	8,472	5,578	74	0	0
Gas/Oil	10,277	8,351	31	0	0
Wind	4,412	611	38	0	0
Biofuel	495	300	9	0	0
Solar	380	38	8	0	0
Total	**37,044**	**26,415**	**165**	**0**	**0**

4.1 Assessment Assumptions

4.1.1 Generation Resources

All generation projects that are scheduled to come into service, or those scheduled to 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 under the Application Status section of the IESO website.

The "estimated effective date" column 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 August 2, 2018. If a project is delayed, the estimated effective date will be the best estimate of the completion of market registration for the project that is available to the IESO by the cutoff date.

Table 4.2: Committed Generation Resources Status

Project Name	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered	
					Firm (MW)	Planned (MW)
Thunder Bay Generating Station	Northwest	Biomass	2018-Q2	Contract Terminated	-153	-153
Amherst Island Wind	East	Wind	2018-Q3	Commercial Operation	74	74
Yellow Falls	Northeast	Hydro	2018-Q4	Under Development		16
Douglas Generating Station	Toronto	Gas	2018-Q4	Expiring Contract	-122	-122
Napanee Generating Station	East	Gas	2019-Q1	Under Development		985
Loyalist Solar	East	Solar	2019-Q1	Under Development		54
Nanticoke Solar	Southwest	Solar	2019-Q1	Under Development		44
Whitby Cogeneration	Toronto	Gas	2019-Q2	Expiring Contract	-56	-56
Henvey Inlet Wind Farm	Essa	Wind	2019-Q2	Under Development		300
Total					**-257**	**1,143**

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, using the following terminology:
    a. Under Development – projects in approvals and permitting stages (e.g., environmental assessment, municipal approvals, IESO connection assessment approvals, etc.) and projects under construction.
    b. Commissioning –projects that are undergoing commissioning tests with the IESO.
    c. Commercial Operation –projects that have achieved commercial operation status under the contract criteria, but have not met all of the IESO's market registration requirements.
    d. Expiring Contract – Includes 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.
    e. Contract Terminated – includes projects that have been terminated.

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 (see the "Historical hydroelectric median values (MW)" row in Table 4.3). In order to reflect the impact of hydroelectric outages on the "reserve above requirement" (RAR) and allow the assessment of hydroelectric outages as per the outage approval criteria, the hydroelectric capability without accounting for historical outages is also calculated (see the "historical hydroelectric median values without outages (MW)" row of Table 4.3). Table 4.3 uses data from May 2002 to March 2018, which 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)	6,049	5,991	5,851	5,794	5,843	5,697	5,634	5,338	5,068	5,377	5,692	6,082
Historical Hydroelectric Median Values without Outages (MW)	6,550	6,535	6,338	6,296	6,295	6,162	6,080	5,830	5,807	6,068	6,277	6,524

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, 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, which 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%	33.6%	35.4%	22.8%	13.6%	13.6%	13.6%	14.8%	29.8%	36.5%	37.8%

Solar

For solar generation, 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, which are updated annually to coincide with the release of the summer Outlook.

Due to the increasing penetration of embedded solar generation, the grid demand profile has been changing, with summer peaks being pushed to 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 and demand response procured through an annual demand response auction, 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. The impacts of actual activations of demand measures are added back into the demand history prior to forecasting demand for future periods.

For the summer and winter six-month commitment periods (beginning May 1, 2018 and November 1, 2018), 563.2 MW and 712.4 MW of DR capacity respectively were procured through the 2017 DR auction (capacity acquired through the annual auction is reflected in this Outlook). The next DR auction is scheduled to take place in December 2018 for delivery of capacity in the summer 2019 and winter 2019/2020 periods. The Pre-Auction Report will be published September 20, 2018. As discussed with stakeholders through the Demand Response Working Group, the IESO will be maintaining the DR Auction target capacity at the levels used for the 2017 DR Auction.

4.1.4 Firm Transactions

Capacity Backed Export

For October 2018, 452.9 MW of Ontario capacity has been cleared in New York's monthly auctions. The 18-Month Outlook reflects the cleared amounts in the NYISO auctions, as posted on the NYISO website. The NYISO's next auction to procure up to 453 MW capacity for the 2018/2019 six-month winter period will be held in the last week of September.

System Backed Export

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 2.3 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.

As part of this capacity exchange agreement, the 500 MW capacity delivered to Quebec in 2015/2016 winter will have to be returned to Ontario during summer before September 2030, based on Ontario's needs. This capacity was not requested for summer 2019.

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)	37,044	
New Generation and Capacity Changes (MW)	1,143	-257

The starting point for 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** assumes resources are restricted to those that have reached commercial operation status. Generator-planned shutdowns or retirements that have a 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** also considers DR programs from future participants. 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	Winter Peak 2019		Summer Peak 2019		Winter Peak 2020	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,843	36,860	36,787	38,187	36,787	38,187
2	Total Reductions in Resources (MW)	10,092	10,056	10,559	10,905	10,342	10,534
3	Demand Measures (MW)	795	795	567	567	795	795
4	Firm Imports (+) / Exports (-) (MW)	-500	-500	0	0	-500	-500
5	Available Resources (MW)	27,046	27,098	26,795	27,849	26,740	27,947

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). This may vary from the Forecast Capability at System Peak shown in Table 4.1 due to the impacts of demand measures and bottling of generation.

4.2 Capacity Adequacy Assessment

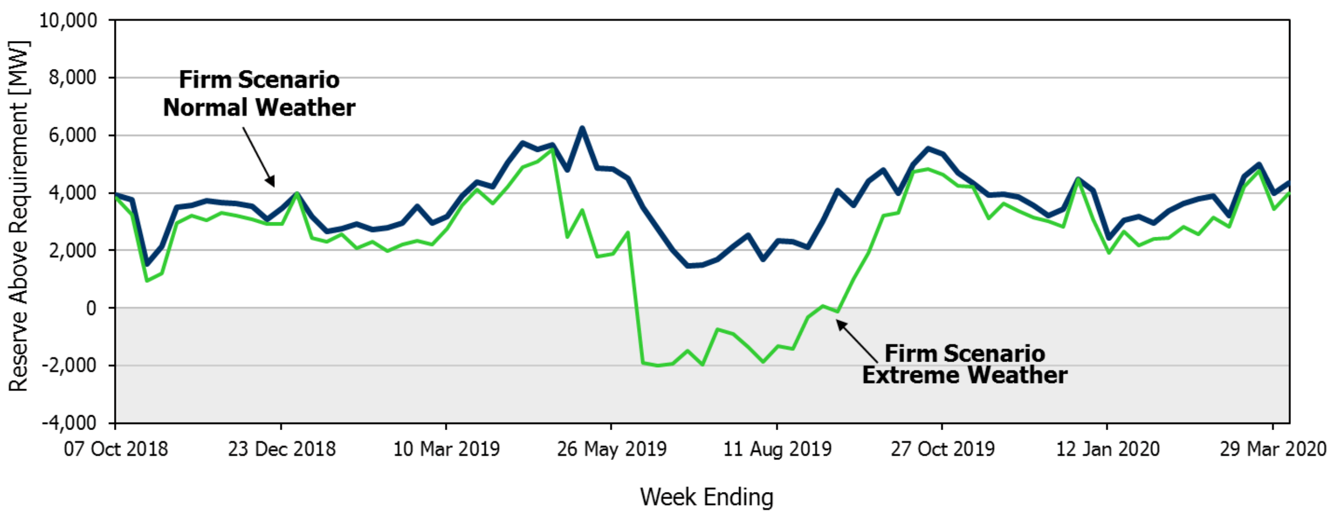
The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages, and have been assessed as of August 3, 2018. The generation planned outages occurring during this Outlook period have been assessed as of August 24, 2018.

4.2.1 Firm Scenario with Normal and Extreme Weather

The **firm scenario** incorporates all existing capacity that had achieved commercial operation status as of August 2, 2018.

Figure 4.1 shows reserve above requirement (RAR) levels, which represent the difference between available resources and required resources. The latter equals the demand plus required reserve. As can be seen, the reserve requirement in the **firm scenario** under normal weather conditions is met throughout the entire Outlook period. In the firm scenario, during extreme weather conditions, the reserve is lower than the requirement for a total of 13 weeks (without reliance on imports) during the same timeframe. Under the current outage schedule, the RAR remains above the -2,000 MW threshold. This potential shortfall is largely attributed to planned generator outages scheduled during those weeks. If extreme weather conditions materialize, the IESO may reject some generator maintenance outage requests to ensure that Ontario demand is met during the summer peak periods. For weeks where the RAR is close to the resource adequacy threshold for approving outages, generators expecting to perform maintenance on their units are advised to review their planned maintenance plans and consider rescheduling them if they are critical for the continued operation of the units, as any changes to Ontario's import capability or other operational challenges may pose scheduling challenges in summer 2019.

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

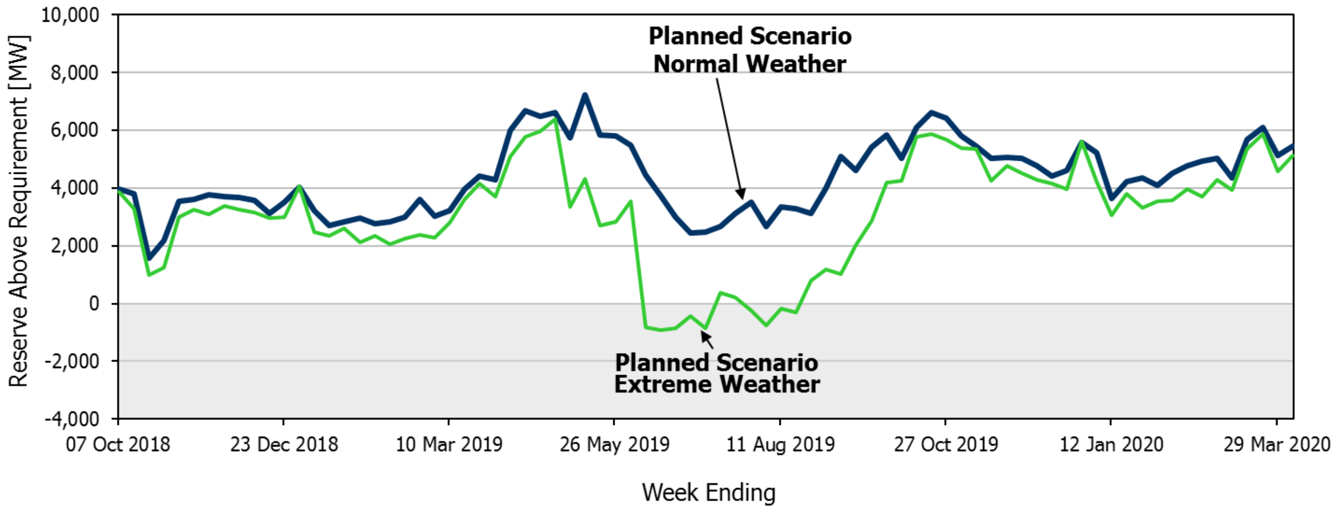


4.2.2 Planned Scenario with Normal and Extreme Weather

The **planned scenario** incorporates all existing capacity plus all capacity coming into service. Approximately 1,473 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.

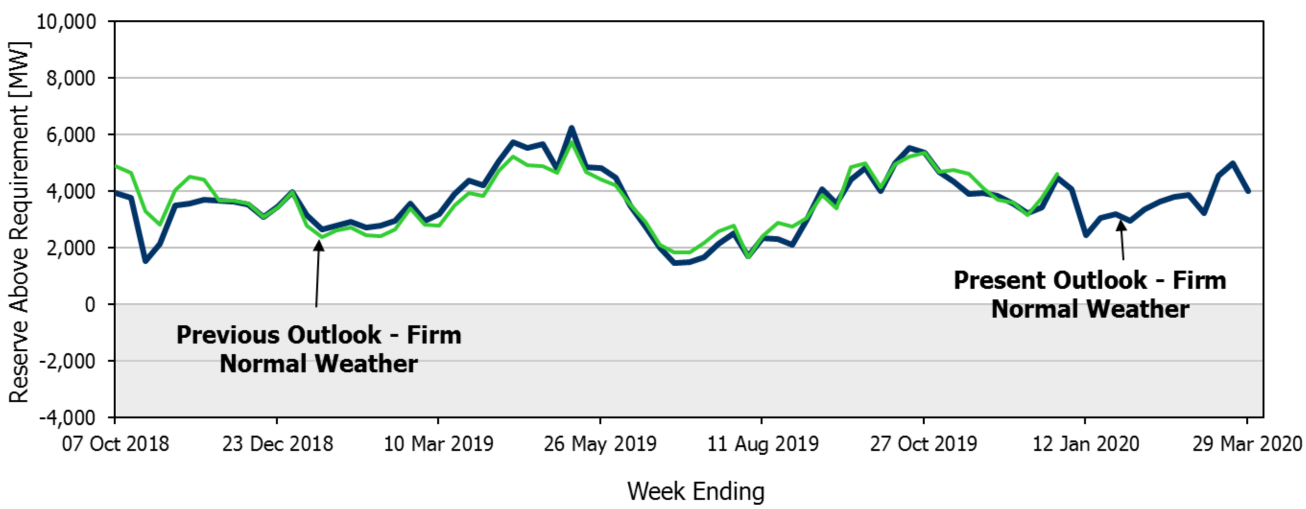
Figure 4.2: Normal vs. Extreme Weather: Planned Scenario RAR



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 current Outlook and those in the previous Outlook published on June 20, 2018. The difference is primarily the result of 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 both to determine whether Ontario has sufficient supply to meet its forecast energy demands and to highlight potential adequacy concerns during the Outlook timeframe. At the same time, the assessment estimates the aggregate production by 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) uses the same set of assumptions pertaining to resources expected to be available over the next 18 months as the capacity assessment. For this information, refer to Table 4.1 for the summary of existing generation capacity and Table 4.2 for the status of generation resources. The monthly forecast of energy production capability, based on the energy modelling results, is included in Table A7 of the 2018 Q3 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's 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 both for Ontario and for 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	**202.7**	**15,414**	**202.7**	**15,414**	**0.0**	**456.1**	**587.2**
Bruce	0.9	72	70.0	5,325	69.1	0.9	134.8
East	13.5	1,030	16.4	1,248	2.9	27.1	82.0
Essa	12.0	910	0.6	43	-11.4	25.0	7.4
Niagara	6.2	475	19.4	1,479	13.2	15.5	45.4
Northeast	16.0	1,214	13.0	989	-3.0	26.0	38.4
Northwest	7.4	564	6.8	518	-0.6	12.6	19.6
Ottawa	11.7	887	0.0	1	-11.7	26.6	2.5
Southwest	39.5	3,003	6.0	452	-33.5	90.6	14.9
Toronto	76.0	5,775	61.8	4,697	-14.2	184.4	153.7
West	19.5	1,483	8.7	661	-10.8	47.4	76.3

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 – October 1, 2018, to March 31, 2019

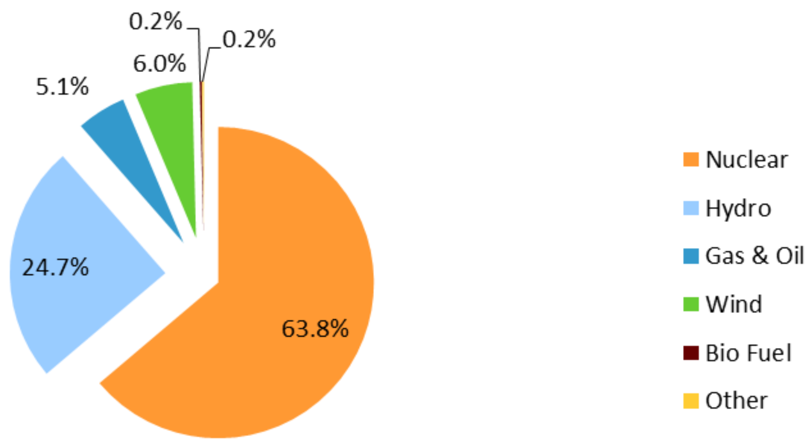


Figure 4.5: Monthly Production by Fuel Type – October 1, 2018, to March 31, 2019

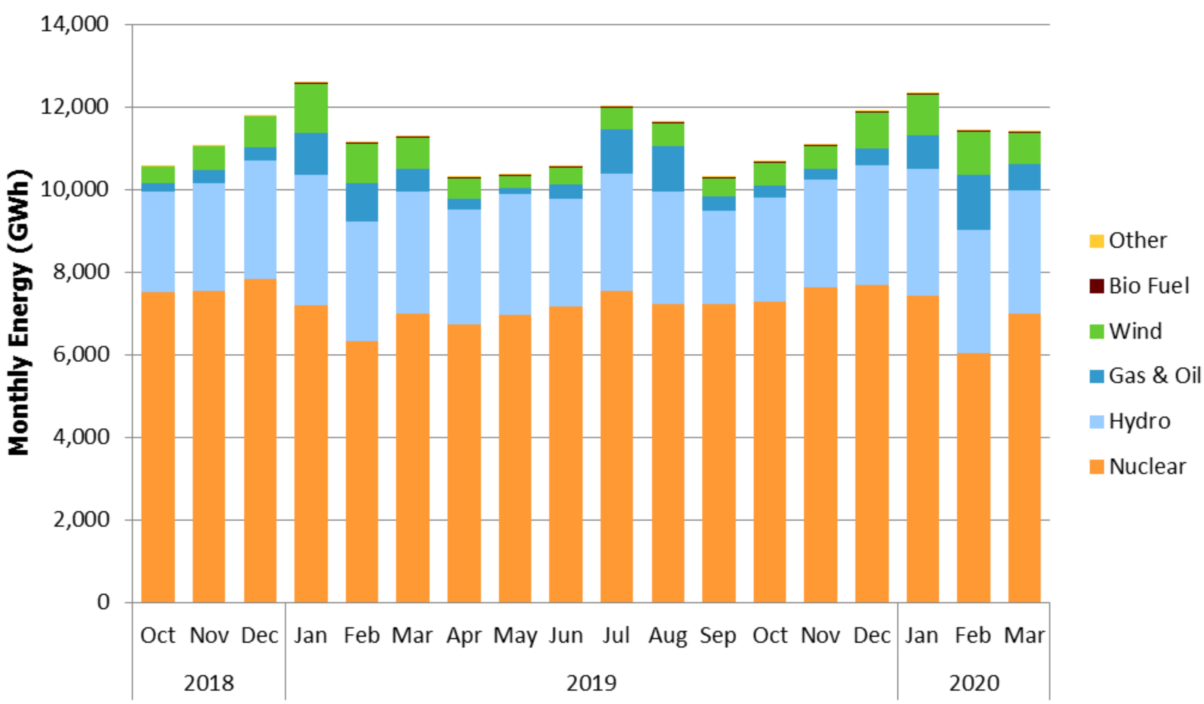


Table 4.9: Firm Scenario – Normal Weather: Ontario Energy Production by Fuel Type

Fuel Type (Grid Connected)	2018 (Oct 1 - Dec 31)	2019 (Jan 1 - Dec 31)	2020 (Jan 1 - Mar 31)	Total
	(GWh)	(GWh)	(GWh)	(GWh)
Nuclear	22,873	86,035	20,474	129,381
Hydro	7,933	33,145	9,023	50,102
Gas & Oil	835	6,749	2,768	10,353
Wind	1,713	7,580	2,812	12,105
Bio Fuel	67	278	72	416
Other (Solar & DR)	27	257	79	363
Total	**33,448**	**134,045**	**35,227**	**202,720**

4.4 Outage Assessment Updates

As was previously reported in the Q2 18-Month Outlook, the IESO's outage management criterion for assessing adequacy has changed. All outages occurring from May 2019 onward will be evaluated for resource adequacy using extreme weather instead of normal weather conditions under the firm resource scenario and assume that up to 2,000 MW of imports are available for determining RAR sufficiency. Participants should benefit from improved certainty in obtaining outages with this new criterion. The new outage approval criteria will allow more planned outages in the winter or shoulder months when there are sufficient RAR. To facilitate these changes, modifications were made to Market Manual 7.2 on June 2018. More information can be found on the stakeholder webpage: http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/proposed-ieso-outage-approval-criteria

Wind generators are reminded of the new "icing event" purpose code in the IESO's outage management tool. Use of this purpose code will improve the accuracy of variable generation forecasts for icing conditions by ensuring that occurrences of de-rated generation output capacity specifically due to icing are highlighted to the centralized forecast provider.

- 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 27, 2018.

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. While the Ontario transmission system is capable of serving the demand under the normal and extreme conditions forecast for the Outlook period, some outage combinations can create transmission limitations. In particular, transmission limitations have been identified in the Flow East toward Toronto (FETT) interface during the 18-Month Outlook period due to concurrent planned outages submitted for generation resources located east of this interface. Following contingencies involving the loss of transmission elements on this interface, there may not be sufficient resources available to restore the reliability of the power system. As a result of these limitations, outages submitted for generation resources located east of FETT, or transmission elements that comprise FETT may be affected. These limitations are expected to persist for the duration of Ontario's nuclear refurbishment program.

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 across the province through regional planning with projects being initiated to address local area needs. For additional information on IESO's regional planning activities, visit the IESO regional planning webpage

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 Q4 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.

The new Copeland station, when in-service in Q4 2018, 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 facilities at John TS.

As was recommended in the Central Toronto Integrated Regional Resource Plan (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 peak demand in the area. In addition, it will serve the new Eglinton Light Rail Transit project currently under construction.

On July 27, 2018, a transformer fire at Finch TS resulted in all four transformers at the station being taken off line. Approximately 100 MW of load in Toronto was affected. Most LDC loads were able to be resupplied from alternate supplies. All load has since been restored; however, transformers T1 and T2 remain out of service.

Transmission transfer capability in Toronto and the 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's replacement of aging infrastructure at the Bruce 230 kV switchyard is scheduled to be completed by Q4 2020. 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 2018. In addition to replacing the existing special protection system, this new RAS will feature 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 is underway with an expected in-service date of Q2 2019. Once completed, this project will 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, part of the transmission network path between Eastern Ontario and the major load centres near the GTA. Reinforcement on the Hawthorne-to-Merivale path would be required if resources from Quebec were to participate in Ontario's capacity auction.

On April 30, 2018, the Phase Angle Regulator (PAR) connected to ON-NY 230 kV interconnection circuit L33P failed. The failed PAR initially came into service in 1962, and options for its replacement are currently being considered. The aim is to have a new PAR installed in the next few years.

Having the PAR and by association L33P out of service has resulted in a tighter band of operation on our New York-St. Lawrence interconnection, and within Ontario at St. Lawrence. These constraints impact our ability to import from NY through the New York-St. Lawrence interconnection and from Quebec through the Beauharnois interconnection. The long-term outage also requires more focused management of area resources in real-time, and introduces complexity in responding to forced outages and planning maintenance outages.

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 that Hydro One 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.

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.

Due to increased growth in the greenhouse sector in the Windsor-Essex region within the West zone, forecast transmission limitations for a local area may emerge in early 2020. Transmission planning investigating both supply- and demand-side options is currently underway for this region to identify a long-term solution in this region. In the interim, a special protection scheme will be implemented to allow for an expansion of the existing Leamington TS.

5.2.6 Northeast and Northwest Zones

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, output of the generating facilities in the Kapuskasing area may need to be limited whenever these high transfers occur.

To maintain future supply reliability in the Kapuskasing area, Hydro One filed a Leave to Construct application to reinforce the system in the area as recommended by the IESO. The OEB has approved the Leave to Construct application and the Kapuskasing Area Reinforcement project is expected to be in-service as early as Q42019.

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, but generation in Northwestern Ontario will continue to be limited by the remaining constraints in the Sault Ste. Marie and Sudbury areas. The East-West Tie expansion project is primarily required to ensure reliability of supply to the northwest while accommodating the forecast load growth in the region. The Leave to Construct applications for this project have been file, and, as requested by the Minister of Energy, on December 1, 2017 the IESO completed and submitted an updated assessment of the need for the line, confirming the East-West Tie expansion project continues to be the least cost solution for meeting the region's reliability needs.. The IESO recommends that work continue to target an in-service date of Q4 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

Implementation of the Phase I and Phase II energy storage programs are well underway, with many of the projects achieving Commercial Operation or are being commissioned. These storage facilities are expected to provide essential grid services, such as regulation, reactive support and voltage control.

The Energy Storage Advisory Group (ESAG) was established in spring 2018 to support and assist the IESO in evolving policy, rules, processes and tools to better enable the integration of storage resources within the current structure of the IESO-administered market. The advisory group's focus for late Fall 2018 will be on providing input to the IESO's work plan and/or list of priorities to address storage related issues and opportunities within the current IESO-administered markets, including tools and operational arrangements. More details can be found at the ESAG engagement website at http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/energy-storage-advisory-group.

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 intertie 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 and linked wheel transaction curtailments could also be utilized to alleviate potential surplus conditions. These actions usually, but not always, occur when Ontario demand is at its lowest.

Ontario will continue to experience potential surplus baseload conditions during the Outlook period. Much of the surplus baseload conditions can be managed with existing market mechanisms, such as exports and curtailment of variable generation. Increased use of nuclear manoeuvers is frequently expected in spring 2019 and may be required in summer and fall 2019.

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 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, 2018. These values are updated annually to coincide with the release of the summer 18-Month Outlook.

Figure 6.1 Minimum Ontario Demand and Baseload Generation

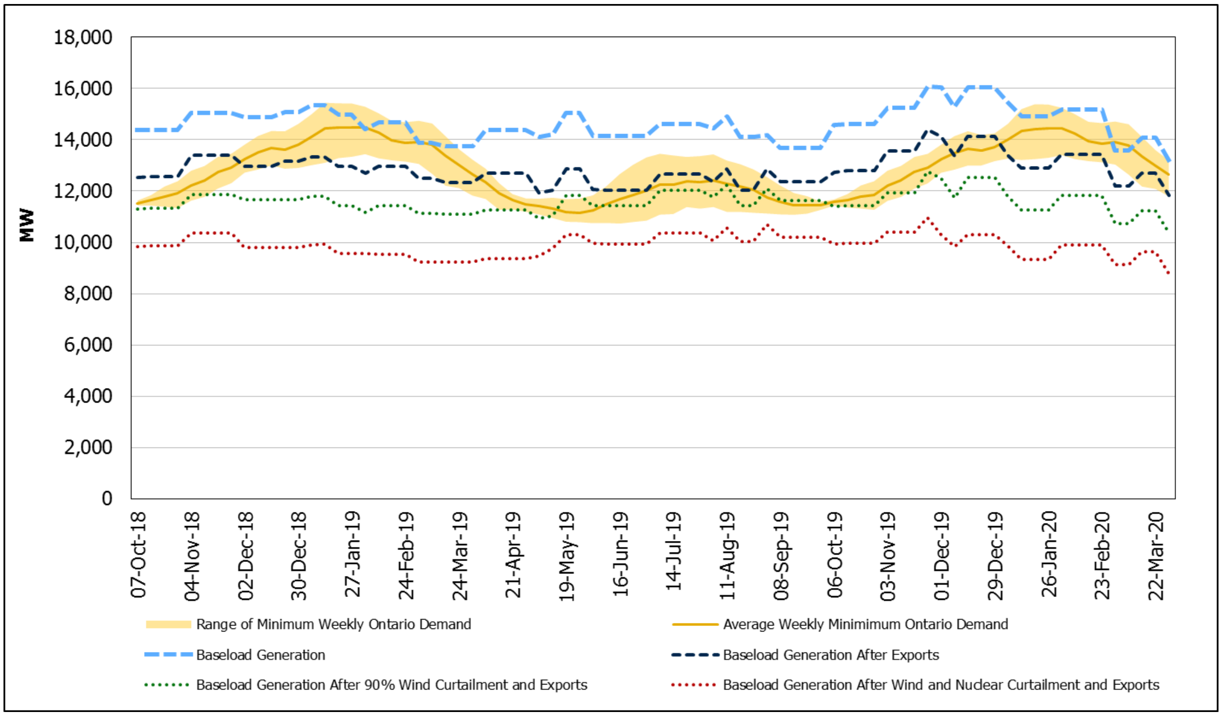


Table 6.1: Monthly Off-Peak Wind Capacity Contribution Values

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Off-Peak WCC (% of Installed Capacity)	37.8%	37.8%	33.9%	35.8%	25.1%	15.2%	15.2%	15.2%	18.8%	31.0%	38.2%	37.8%

6.3 Distributed Energy Resources

Distributed energy resources (DERs) are electricity-producing resources or controllable loads that are directly connected to the distribution system or that are located behind customers' meters and indirectly connected to the distribution system. DERs can include small natural gas-fuelled generators, combined heat and power plants, electricity storage, solar photovoltaics (PV), electric vehicles and controllable loads, such as HVAC systems and electric water heaters. Embedded generation, as shown in Table 3.3.6 of the 2018 Q3 Outlook Tables, is a subset of DERs. This table only includes generation contracted by the IESO.

With contributions from DERs growing in Ontario, , the IESO has seen periods where these resources have significantly reduced demand by offsetting the load on the distribution system and, in some cases, supplying enough energy to flow energy back into the transmission system. This creates challenges in how we forecast Ontario demand and in changing transmission flow patterns across the province. As the Reliability Coordinator and Balancing Authority for Ontario, we must understand the impacts and benefits of DER and work closely with providers and LDCs so we can effectively operate an integrated power system.

The rising penetration of DERs means that more data needs to be shared between the IESO and LDCs and DER operators to provide the control room visibility required to improve forecasting and dispatch.

The Grid-LDC Interoperability Standing Committee is actively engaged in pilots with several LDCs to share static and telemetered data to advance the IESO's forecasts and increase accuracy. In addition, the Committee is developing a joint Operational Capability Risk Assessment and planning a workshop in fall 2019 to identify the capabilities required to mitigate risks and take advantage of opportunities. The risk assessment will help identify both areas of overlap between LDCs, DERs and the IESO, and opportunities for enhanced communication, coordination and interoperability. More information is available on the Grid-LDC Interoperability Standing Committee webpage.

- End of Document -

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