
Reliability Outlook

An adequacy assessment of Ontario's
electricity system

FROM JANUARY 2019 TO DECEMBER 2023

Executive Summary

The Independent Electricity System Operator (IESO) ensures the reliability of Ontario's power system on behalf of all Ontarians. Balancing electricity supply and demand depends on comprehensive short- and long-term planning that enables the IESO to continue to meet reliability requirements in the face of shifting demand patterns, while giving market participants the data and insights they need to make informed operational and investment decisions.

The quarterly *Reliability Outlook* (formerly known as the *18-Month Outlook*) presents Ontario's demand forecast and associated drivers, resource adequacy projections and the assumptions that inform them, as well as an assessment of operability and the province's transmission assets. As part of our commitment to open and transparent planning, this edition marks the first time the IESO has extended the traditional 18-month planning horizon for an additional 42 months, providing a five-year assessment of reliability.

Published every June and December, these extended outlooks will address the drivers – including nuclear refurbishments, changing transmission flow patterns, and end of supply contracts – that can affect resource adequacy, and require the IESO to address associated reliability risks through outage management.

Planning for a reliable electricity system

The outlook for resource availability remains positive over the next 18 months with sufficient resources to maintain the reliability of Ontario's electricity system, under normal weather conditions. Under extreme weather conditions, without reliance on imports, reserves are below requirement for one week in late summer 2019.

When reserves are below required levels, the IESO will mitigate reliability risks through outage management, potentially rejecting outage requests based on their order of precedence. Generators expecting to perform maintenance during the summer of 2019 are advised to review plans and consider rescheduling outages.

In 2018, grid-supplied energy rebounded to post-recession levels, after a significant drop in demand across all sectors of the economy in 2017. In 2019, demand growth is expected to be fairly flat with small year-over-year increases and decreases.

Operational challenges and experience gained

Advanced grid technologies, changing supply and demand patterns, and extreme weather are increasing the challenges associated with managing and operating Ontario's power system.

With over 4,000 MW in-service or under development in Ontario, and this quantity expected to rise, distributed energy resources (DERs) are changing the composition of Ontario's resource mix, and contributing to the decentralization of the grid. While they present opportunities to optimize overall investments and

support grid reliability, the IESO needs visibility into their operations to forecast their output over different timeframes, and study their impact on reliability.

The IESO is assessing the opportunities and planning challenges associated with the rapid rise of DERs, working with stakeholders to understand the impact on the transmission-distribution interface, and exploring areas for further collaboration and data sharing.

Bloomberg New Energy Finance has predicted that the global energy storage market will double six times between 2016 and 2030. According to the European Commission, the cost of energy storage batteries is expected to continue to tumble. Between 2007 and 2014, costs dropped by 70 per cent and are expected to do the same again by 2030.

Implementation of the Phase I and Phase II energy storage programs are well underway. By the end of 2018, 13 of the 20 energy storage projects are expected to achieve commercial operation and the remaining seven are expected by November 2019.

More diverse supply mix

Over the last decade, Ontario's energy sector has witnessed the growth of a more robust and diverse supply mix, with natural gas and hydroelectric generation, growing demand response resources, and significant increases in wind and solar generation installed on the transmission and distribution systems.

About 1,500 megawatts (MW) of new supply – 985 MW of gas, 400 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 next 18 months. By the end of the period, the amount of grid-connected wind and solar is expected to increase to 4,886 MW and 478 MW respectively, and embedded wind and solar is expected to be about 1,050 MW and 2,287 MW respectively.

Transmission considerations

Ontario's transmission system is expected to continue to reliably supply province-wide demand, while experiencing the normal contingencies defined by planning criteria for the next 18 months. Beyond this period, some combinations of transmission and/or generation outages can create operating challenges.

Transmission capability of the Flow East Toward Toronto (FETT) interface, which permits the transfer of power to Toronto from generation in the Bruce, Niagara, Southwest and West regions of the province, could be reduced significantly with one or more key transmission elements out of service. With planned refurbishments in Darlington and the retirement of the Pickering Nuclear Generating Station, generators located east of the FETT will face additional outage scheduling challenges.

The failure of the phase angle regulator connected to the Ontario-New York 230KV interconnection circuit L33P earlier this year has impacted the IESO's ability to import from New York and from Quebec. Replacement options are being investigated through the joint efforts of the New York Power Authority, the New York Independent System Operator and the IESO.

Beyond 18 months

Starting with this issue, which covers the 42-month period from July 2020 to December 2023, the extended Reliability Outlook will be published twice a year – prior to winter and summer. While the data for the extended timeframe will necessarily be more imprecise, the longer-term view is intended to address changes in resource adequacy and transmission flow patterns.

Uncertainties in the five-year horizon include economic and demographic conditions, achievement of energy-efficiency goals, penetration of embedded generation, weather conditions, timing and completion of transmission and resource projects and the scheduling of planned and forced outages.

The IESO's outage management planning ensures the adequacy and operability of the system is maintained. A number of contributing factors need to be considered when addressing system needs in 2020 and beyond, including the retirement of the Pickering Nuclear Generating Station and refurbishments at Darlington and Bruce Nuclear Generating Stations. In providing greater transparency by identifying, well in advance, periods in which adjustments to outages may be required to mitigate generation and transmission adequacy concerns, the IESO's goal is to enable market participants to plan appropriately, while better serving system needs.

Maintaining the reliability of the province's electricity system on behalf of all Ontarians is at the core of the IESO's mandate. Electricity planning ensures there is sufficient supply to meet the electricity needs of the system now and in the future. The current forecast shows a potential capacity requirement in 2023 – a time when long-term contracts with generation facilities begin to expire, and nuclear units are being refurbished or retired. The IESO will continue to update and engage with stakeholders to review and refine our resource adequacy forecasts, and where necessary, make decisions about meeting our resource requirements.

Fundamental changes to the electricity market are underway to improve and strengthen the structure of the market and effectively provide the capacity the system needs when it needs it. Moving beyond 2023, the IESO is committed to implementing competitive auctions, introduced through its [Market Renewal Program](#), to prepare for and address future supply needs in the province.

Contents

Executive Summary	1
1. Introduction	7
2. Updates to This Outlook	8
2.1 Updates to Demand Forecast	8
2.2 Updates to Resources	8
2.3 Updates to Transmission Outlook	8
2.4 Updates to Operability Outlook	8
3. Demand Forecast for 18-Month Period	9
3.1 Actual Weather and Demand	11
3.2 Forecast Drivers	17
3.2.1 Economic Outlook	17
3.2.2 Weather Scenarios	17
3.2.3 Pricing, Conservation and Embedded Generation	17
4. Resource Adequacy for 18-Month Period	18
4.1 Assessment Assumptions	19
4.1.1 Generation Resources	19
4.1.2 Generation Capability	20
4.1.3 Demand Measures	22
4.1.4 Firm Transactions	22
4.1.5 Summary of Scenario Assumptions	22
4.2 Capacity Adequacy Assessment	23
4.2.1 Firm Scenario with Normal and Extreme Weather	23
4.2.2 Planned Scenario with Normal and Extreme Weather	24
4.2.3 Comparison of the Current and Previous Weekly Adequacy Assessments for the Firm Normal Weather Scenario	25
4.3 Energy Adequacy Assessment	26
4.3.1 Summary of Energy Adequacy Assumptions	26
4.3.2 Results – Firm Scenario with Normal Weather	26
4.3.3 Findings and Conclusions	27
5. Transmission Reliability Assessment	29
5.1 Transmission Outages	29
5.2 Transmission Considerations	29
6. Operability	31
6.1 Surplus Baseload Generation	31
6.2 Distributed Energy Resources and Emerging Technologies	33

7. Beyond 18 Months	35
7.1 Introduction	35
7.1.1 Interpretation	35
7.2 Key Findings	36
7.3 Capacity Adequacy Assessment	36
7.3.1 Summary of Scenarios Considered	37
7.3.2 Capacity Adequacy Findings	38
7.4 Inputs and Assumptions	39
7.4.1 Demand	41
7.4.2 Changes to installed generation	43
7.4.3 Firm Transactions	44
7.5 Transmission Outlook	44
8. Resources Referenced in This Report	45
9. List of Acronyms	46

List of Figures

Figure 4-1 Monthly Wind Capacity Contribution Values	21
Figure 4-2 Monthly Solar Capacity Contribution Values	21
Figure 4-3 Comparison of Normal and Extreme Weather: Firm Scenario Reserve Above Requirement	24
Figure 4-4 Comparison of Normal and Extreme Weather: Planned Scenario Reserve Above Requirement	25
Figure 4-5 Comparison of Current and Previous Outlook: Firm Scenario Extreme Weather Reserve Above Requirement	25
Figure 4-6 Energy Production by Fuel Type: January 1, 2019 to June 30, 2020	27
Figure 4-7 Monthly Energy Production by Fuel Type: January 1, 2019 to June 30, 2020	28
Figure 6-1 MWh Curtailments versus Ontario Demand	31
Figure 6-2 Minimum Ontario Demand and Baseload Generation	32
Figure 6-3 Minimum Ontario Demand and Baseload Generation	32
Figure 6-4 Monthly Off-Peak Wind Capacity Contribution Values	33
Figure 7-1 Reserve Above Requirement for All Anticipated Outages and All Scheduled Outages Scenarios	39

List of Tables

Table 3-1 Historical And Forecast Energy Summary	10
Table 3-2 Forecasted Seasonal Peaks	11
Table 3-3 Weekly Energy and Peak Demand Forecast	14
Table 4-1 Existing Grid-Connected Resource Capacity as of November 23, 2018	18
Table 4-2 Committed Generation Resources Status	19

Table 4-3 Monthly Historical Hydroelectric Median Values for Normal Weather Conditions	20
Table 4-4 Summary of Available Resources under Normal Weather	23
Table 4-5 Summary of Zonal Energy for Firm Scenario Normal Weather	26
Table 4-6 Ontario Energy Production by Fuel Type for the Firm Scenario Normal Weather	28
Table 7-1 Notable Issues or Findings	36
Table 7-2 Summary of Scenarios	37
Table 7-3 Summary of Available Resources (MW) at Summer Peak	38
Table 7-4 Methodological Differences from the 18-Month Horizon	40
Table 7-5 Summary of Forecasted Peaks and Energy	41
Table 7-6 Monthly Energy and Peak Demand Forecast	42
Table 7-7 Committed Generation Resources Status	43
Table 7-8 Generation Facilities whose Contract Expire during this Outlook Period	44
Table 8-1 Additional Resources	45

Copyright © 2018 Independent Electricity System Operator. All rights reserved.

1. Introduction

This Outlook covers two distinct periods: the 18-month period from January 2019 to June 2020, which supersedes the Outlook released on September 20, 2018 and is presented in chapters 3 - 6, and the 42-month period from July 2020 to December 2023, presented in chapter 7.

The quarterly *Reliability Outlook* (formerly known as the *18-Month Outlook*) has been renamed to reflect the extended planning horizon, to be published every June and December with an additional 42 months, providing a five-year assessment of reliability. The 18-month assessment will continue to be published in accordance with the requirements provided in the Market Rules, Chapter 5, Power System Reliability. The affected market manual and related form will be updated through the baseline process.

The purpose of the 18-month horizon in the *Reliability 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, and
- Report on initiatives being implemented to improve reliability within this timeframe.

The 42-month period presented in chapter 7 is intended to support generation and transmission owners with scheduling and approval of outages and to inform changes in resource adequacy beyond 18 months that may make outage coordination and assessments more challenging in the future.

Additional supporting documents are located on 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 assumptions, readers are encouraged to use their 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
- E-mail: customer.relations@ieso.ca

2. Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast used in the entirety of this Outlook is informed by actual demand, weather and economic data through to the end of September 2018, and has been updated to reflect the most recent economic projections. Actual weather and demand data for October and November are included in the [tables](#).

2.2 Updates to Resources

This *Reliability Outlook* considers planned generator outages submitted by market participants to the IESO's outage management system as of November 13 for the entirety of the 60 months. Market participants are required annually to submit information to enable the IESO to conduct reliability assessments. This information, provided to the IESO through Form 1230, was submitted by April 1, 2018.

On July 27, 2018, Ontario Power Generation (OPG) announced the closure of Thunder Bay GS (153 MW) and has since begun the deregistration process. Amherst Island CGS (74.1 MW) completed the market registration process since the last Outlook. All of these changes are reflected in Table 4-1 of this Outlook.

2.3 Updates to Transmission Outlook

Transmission outage plans that were submitted to the IESO's outage management system by October 25, 2018, are considered in 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 November 13.

3. Demand Forecast for 18-Month Period

Over the forecast period, peak demands will continue to face downward pressure from energy efficiency and the effects of the Industrial Conservation Initiative (ICI). Grid-supplied energy demand rebounded in 2018 compared to 2017. Demand was anomalously low in 2017 and 2018's rebound is a continuation of the trend since 2009 toward flat demand with small year-over-year increases and decreases.

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period January 2019 to June 2020 and supersedes the previous forecast released in September 2018. Tables of supporting information are contained in the [2018 Q4 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 reduce peak 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 demand forecast incorporates these impacts.

Grid-supplied demand has been fairly flat since the 2009 recession with small increases and decreases year over year. The exception to this trend occurred in 2017, when demand dropped significantly across all regions of the province and sectors of the economy. Since the start of 2018, demand continued on its previous trajectory. After weather-correcting 2018's energy values thus far, 2018's energy demand is lower than the energy demand for the same period in 2016, even after adjusting for the fact that 2016 was a leap year. When comparing year-to-year demand growth, 2018 is higher than 2017. This is mostly attributable to low demand in 2017.

The demand forecast for the next 18 months is expected to decline compared to 2018, as increased energy-efficiency savings and structural changes to the economy outweigh growth from economic expansion and demographic growth. The announced closure of the General Motors Oshawa plant is emblematic of the long-term economic structural change, as manufacturing declines as a share of Ontario's economy. Embedded generation output also reduces the need for grid-supplied electricity. With capacity additions slowing as Ontario transitions away from FIT/microFIT to net metering for embedded generation, growth in embedded output is expected to plateau.

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 rate impacts (ICI and time-of-use rates). The majority of embedded generation is provided by 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 Table 3-2 shows forecasted seasonal peaks. Table 3-3 shows the weekly peaks and energy demand over the forecast horizon of the Outlook. The tables include both normal and extreme weather peaks. Normal peaks are based on typical weather, while extreme peaks capture the volatility of weather, when the system is most likely to be stressed. Recent IESO experience has found increasing instances of extreme conditions and challenges with managing these extreme conditions in real-time. As a result, the IESO revised some of its planning processes, such as capacity exports and outage assessments, to rely on the extreme weather forecast for approvals.

Table 3-1 | Historical and Forecast Energy Summary

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)	135.7	2.4%
2019 (Forecast)	134.8	-0.5%
2020 (Forecast)	134.3	-0.4%

Table 3-2 | Forecasted Seasonal Peaks

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2018-19	21,506	22,434
Summer 2019	21,958	24,384
Winter 2019-20	21,203	22,084

3.1 Actual Weather and Demand

Since the last forecast, the actual demand and weather data for September, October and November 2018 have been recorded.

September

- September's weather was above normal on average as the month started out hot and humid leading into the Labour Day weekend. Later in the month, severe weather events presented challenges. On September 21, six tornadoes touched down in the Ottawa area, following the interaction of a "fall-like" storm with near-record heat and humidity, before temperatures returned to seasonal norms.
- Demand peaked on Wednesday, September 5, the hottest day of the month with temperatures reaching 33.9 °C (Toronto). The demand peak (23,131 MW) was very close to the 2016 September peak of 23,131 MW (based on metered measurements) on a daily high of 34.5 °C. The peak was reduced by embedded solar production and ICI customers actively reducing their load at the time of the peak.
- The weather-corrected peak¹ (19,784 MW) was consistent with September 2016's 20,000 MW weather-corrected peak.
- Energy demand for the month was 11.2 TWh (10.7 TWh weather corrected), an increase over the previous September but very similar to September 2016.
- The minimum demand for the month (10,809 MW) increased over 2017 but was in line with September values since the last recession. The minimum occurred in the early hours of Sunday, September 9, just four days after setting a system peak demand.
- Embedded generation for the month was 481 GWh, a decrease of 0.2% compared to the previous September. Solar output decreased 2.1% and wind output decreased 4.9% compared to the previous September. Non-contracted distributed generation increased, offsetting the decline in output from embedded generators.

¹ Weather-correction is a method of standardizing the demand against median weather conditions. This allows comparisons of demand that exclude the impacts of weather volatility.

- Wholesale customers' consumption rose 11.2% over September 2017 and represented the largest monthly gain since October 2010. Most of the explanation lies with the low 2017 demand, rather than growth in 2018, as wholesale customers saw their load drop by 10.6% compared to September 2016. All major sectors saw significant year-over-year increases.

October

- October was consistently cooler than normal with the exception of the warm week and a half to start the month. October's peak was a warm weather peak for the second year in a row.
- The peak occurred on the hottest day of the month when temperatures topped 28°C (Toronto). The peak demand was 18,640 MW (18,036 MW weather corrected) on the Tuesday after Thanksgiving (October 9). The peak was an increase over 2017, but generally in line with the figures since the recession.
- Energy demand for the month was 10.8 TWh (10.6 TWh weather-corrected). Both of these values are consistent with the numbers over the past three years.
- The minimum demand for the month was 11,052 MW and occurred in the early morning hours of Thanksgiving Monday on October 8.
- Embedded generation for the month topped 489 GWh, which represents an 8.2 percent decrease compared to the previous October. Wind and bio-fuel output was up over the previous year; all other fuels showed a decline.
- Wholesale customers' load increased by 0.9% compared to the previous October. Growth was broad-based with the exception of iron and steel, which took a step back.

November

- As the third coldest November over the past 50 years, November was much cooler than normal.
- The actual peak for the month was 20,048 MW occurring on Thursday, November 22. It was the coldest day of the month with afternoon highs of -6.6°C (Toronto). The weather-corrected value was virtually the same at 19,243 MW, which is consistent with the values experienced since the recession.
- Energy demand for the month was 11.4 TWh (11.0 TWh weather-corrected). Both the actual and weather-corrected values are a slight increase over the previous three Novembers.
- Minimum demand of 12,050 MW occurred Wednesday, November 7 at 4 a.m. This is very unusual as most minimums occur on weekends or holidays. This mid-week minimum was a product of the warmest temperatures of the month. Colder temperatures on the weekends drove overnight heating load pushing the minimum to a weekday.

- Embedded generation was 435 GWh for the month, which represents a decrease of 13 percent compared to the previous November. Decreases in wind (8 percent) and solar (19 percent) out-weighed the increase in hydro output (15 percent).
- Wholesale customers' consumption increased 0.4 percent compared to the previous November. All of the major sectors were up with the exception of Pulp & Paper.

Overall, energy demand for the three fall months from September to November was up 4.4% year over year. After adjusting for the weather, demand for the three months showed an increase of 2.1%. Once again the numbers were very close to those experienced in the fall of 2016.

The [2018 Q4 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

Table 3-3 | Weekly Energy and Peak Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
06-Jan-19	20,545	21,858	570	2,617
13-Jan-19	21,506	22,434	547	2,883
20-Jan-19	20,941	21,572	483	2,872
27-Jan-19	20,658	21,755	404	2,878
03-Feb-19	20,707	21,899	734	2,891
10-Feb-19	19,972	21,491	635	2,827
17-Feb-19	19,722	21,202	581	2,780
24-Feb-19	19,378	21,202	501	2,725
03-Mar-19	20,008	21,262	531	2,761
10-Mar-19	19,457	20,376	649	2,713
17-Mar-19	18,342	19,142	611	2,629
24-Mar-19	17,999	18,745	569	2,542
31-Mar-19	17,898	18,926	567	2,541
07-Apr-19	17,605	18,198	471	2,479
14-Apr-19	16,836	17,835	496	2,414
21-Apr-19	16,419	16,713	531	2,335
28-Apr-19	16,375	16,527	721	2,340
05-May-19	17,499	19,926	849	2,322
12-May-19	16,669	19,425	845	2,339
19-May-19	18,240	21,536	1,175	2,365
26-May-19	17,976	21,702	1,330	2,305
02-Jun-19	18,660	21,235	1,292	2,380
09-Jun-19	19,378	23,698	1,055	2,530
16-Jun-19	20,219	23,681	835	2,542
23-Jun-19	21,382	23,949	754	2,609
30-Jun-19	21,570	23,549	1,016	2,643
07-Jul-19	21,958	24,373	814	2,626
14-Jul-19	21,660	23,359	838	2,719
21-Jul-19	21,140	23,371	1,035	2,614
28-Jul-19	21,224	24,031	841	2,691
04-Aug-19	21,848	24,384	958	2,718
11-Aug-19	21,544	24,237	985	2,688
18-Aug-19	20,725	23,833	1,362	2,664
25-Aug-19	20,782	22,837	1,413	2,646

Continued on next page

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
01-Sep-19	19,964	22,472	1,370	2,513
08-Sep-19	18,428	23,311	680	2,364
15-Sep-19	18,826	20,890	781	2,425
22-Sep-19	17,555	19,369	420	2,396
29-Sep-19	16,925	18,208	554	2,334
06-Oct-19	17,203	17,253	786	2,381
13-Oct-19	17,061	17,311	507	2,415
20-Oct-19	17,083	17,637	392	2,352
27-Oct-19	17,359	17,929	318	2,442
03-Nov-19	17,469	18,328	416	2,452
10-Nov-19	18,531	19,302	601	2,565
17-Nov-19	18,845	19,666	342	2,575
24-Nov-19	19,269	19,983	607	2,641
01-Dec-19	19,664	20,740	409	2,685
08-Dec-19	19,617	20,915	555	2,707
15-Dec-19	20,303	21,305	690	2,763
22-Dec-19	20,150	21,240	362	2,758
29-Dec-19	19,130	19,266	528	2,655
05-Jan-20	19,882	20,962	570	2,767
12-Jan-20	21,203	22,084	547	2,883
19-Jan-20	20,628	20,982	483	2,843
26-Jan-20	20,287	21,504	404	2,850
02-Feb-20	20,419	21,693	734	2,882
09-Feb-20	19,787	21,427	635	2,801
16-Feb-20	19,287	20,812	581	2,749
23-Feb-20	19,471	21,190	501	2,713
01-Mar-20	19,591	21,017	531	2,746
08-Mar-20	19,378	20,327	649	2,699
15-Mar-20	17,934	18,470	611	2,580
22-Mar-20	17,788	18,341	569	2,503
29-Mar-20	17,524	18,385	567	2,486
05-Apr-20	17,276	17,918	471	2,455
12-Apr-20	16,662	17,296	496	2,333

Continued on next page

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
19-Apr-20	16,081	16,147	531	2,325
26-Apr-20	16,247	16,709	721	2,322
03-May-20	17,206	19,678	849	2,289
10-May-20	16,541	19,386	845	2,311
17-May-20	17,725	21,229	1,175	2,326
24-May-20	17,536	21,512	1,330	2,269
31-May-20	18,391	21,010	1,292	2,354
07-Jun-20	19,155	23,608	1,055	2,515
14-Jun-20	20,248	23,880	835	2,519
21-Jun-20	20,834	23,496	754	2,587
28-Jun-20	21,279	23,813	1,016	2,645
05-Jul-20	19,394	22,118	814	2,598

3.2 Forecast Drivers

3.2.1 Economic Outlook

The overall economic environment is currently fairly positive for Ontario, based on recent publicly available forecasts. 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, continued interest rate increases from the Bank of Canada, 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 Q4 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 Q4 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, such as dispatchable loads and demand response (DR) procured through an auction, are not incorporated into the demand forecast and are instead treated as resources and described in [Section 4.1.3](#). Load modifiers are incorporated into the demand forecast.

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

Load modifiers include energy efficiency (energy-efficiency programs, codes and standards, and fuel switching), rate structures (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.

4. Resource Adequacy for 18-Month Period

The IESO expects to have sufficient generation supply for most of summer 2019. There are potential risks in early September 2019 that can be mitigated by outage rescheduling. Over the next 18 months, 1,500 MW of new generation are planned to come into service, while approximately 50 MW of generation will reach the end of its contract life.

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 Grid-Connected Resource Capacity as of November 23, 2018

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Outlook Peak (MW)	Number of Stations	Change in Installed Capacity (MW)
Nuclear	13,009	12,053	5	0
Hydroelectric	8,482	5,436	75	10
Gas/Oil	10,277	8,341	31	0
Wind	4,486	611	39	74
Biofuel	295	300	8	-200
Solar	380	38	8	0
Total	36,928	26,779	166	-116

4.1 Assessment Assumptions

4.1.1 Generation Resources

All generation projects that are scheduled to come into service, or 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 under construction, and contracted resources. Details regarding the IESO's CAA process and the status of these projects can be found on the [Application Status](#) section of the IESO website.

The "Estimated Effective Date" column in Table 4-2 indicates best estimated date of the completion of market registration available to the IESO by November 23, 2018. Two scenarios are used to describe project risks. 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. Planned shutdowns or retirements of generators that have a high certainty of occurring in the future are considered for both scenarios.

Table 4-2 | Committed Generation Resources Status

Project Name	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered	
					Firm (MW)	Planned (MW)
Nanticoke Solar	Southwest	Solar	2019-Q1	Under Development	0	44
Yellow Falls	Northeast	Hydro	2019-Q1	Under Development	0	16
Loyalist Solar	East	Solar	2019-Q2	Under Development	0	54
Whitby Cogeneration	Toronto	Gas	2019-Q2	Expiring Contract	-56	-56
Napanee Generating Station	East	Gas	2019-Q2	Under Development	0	985
Henvey Inlet Wind Farm	Essa	Wind	2019-Q3	Under Development	0	300
Nation Rise	East	Wind	2020-Q1	Under Development	0	100
Total					-56	1,443

Notes on Table 4-2:

The total may not add up due to rounding and does not include in-service facilities. Project status provides an indication of the project progress, using the following terminology:

- Under Development – projects in approvals and permitting stages (e.g., environmental assessment, municipal approvals, IESO connection assessment approvals) and projects under construction.
- Commissioning – projects that are undergoing commissioning tests with the IESO.
- 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.
- Expiring Contract – generators whose contracts expire during the Outlook period are included in both scenarios only up to their contract expiry date. Generators (including non-utility generators) that continue to provide forecast output data are also included in the planned scenario for the rest of the 18-month period.

4.1.2 Generation Capability

Hydroelectric

A monthly forecast of hydroelectric generation output 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 first row in Table 4-3). 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 second 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 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 Contribution (MW)	6,349	6,297	6,120	6,084	6,149	5,972	5,938	5,579	5,318	5,686	5,919	6,376
Historical Hydroelectric Median Contribution without Outages (MW)	6,925	6,914	6,691	6,673	6,617	6,497	6,334	6,065	6,159	6,485	6,644	6,908

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 the Reliability Outlook](#). Figure 4-1 shows the monthly WCC values, which are updated annually to coincide with the release of the summer Outlook.

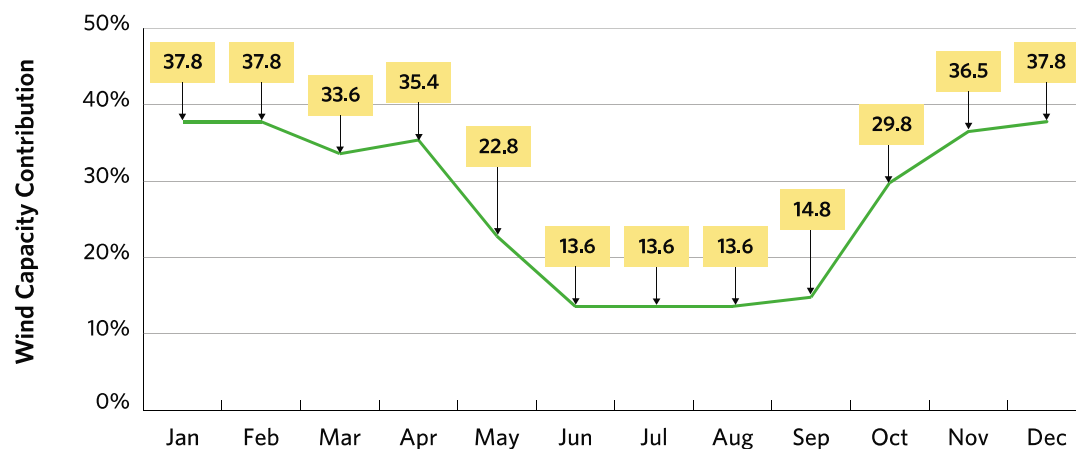


Figure 4-1 | Monthly Wind Capacity Contribution Values

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 the Reliability Outlook](#). Figure 4-2 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.

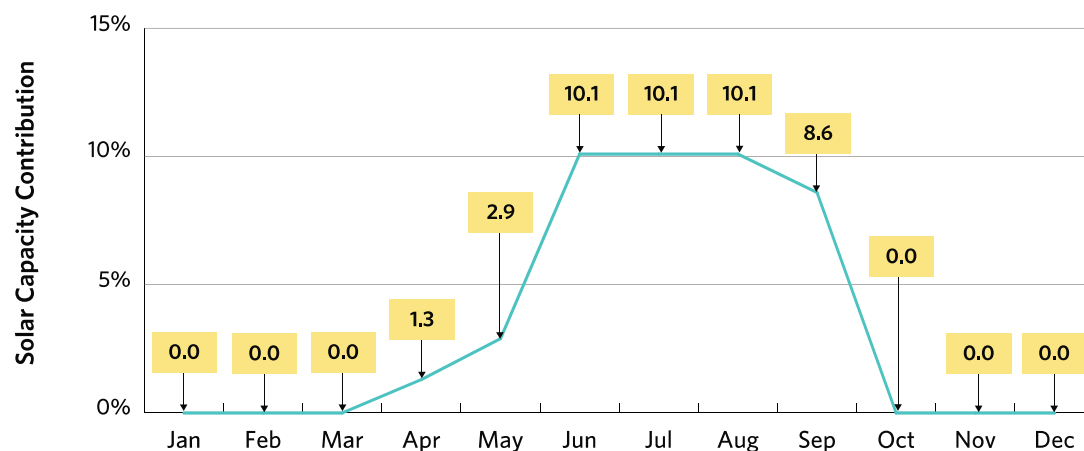


Figure 4-2 | Monthly Solar Capacity Contribution Values

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, such as dispatchable loads and demand response procured through an annual [DR 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 [3.2.3](#) (Pricing, Conservation and Embedded Generation). The impacts of actual activations of demand measures are added back into the demand history prior to forecasting demand for future periods.

For the winter six-month commitment period that began on November 1, 2018, 690.9 MW of DR capacity procured through the 2017 DR auction will be available (capacity acquired through the annual auction is reflected in this Outlook). The 2018 DR Auction, conducted in early December 2018, had a target capacity of 611 MW for the summer commitment period and 606 MW for the winter commitment period. The [results](#) of the 2018 auction were published on December 13 for delivery of capacity in the summer 2019 and winter 2019/2020 period and will be considered in the next *Reliability Outlook*.

4.1.4 Firm Transactions Capacity-Backed Export

The IESO allows Ontario resources to compete in the capacity auctions of some neighbouring jurisdictions if Ontario is adequately supplied. Capacity-backed exports of 354.6 MW were successful in the New York Independent System Operator (NYISO) strip auction for delivery between November 1, 2018 and April 30, 2019. Additionally, between 50-70 MW (varies by month) has been cleared to participate in the NYISO monthly auctions for January to April 2019.

As part of the current implementation of the [Enabling Capacity Exports](#) initiative, the IESO is no longer able to facilitate the export of capacity to Quebec. The IESO and Hydro Quebec have been discussing amendments to the protocols that govern the scheduling of capacity exports in real-time. However, we have not been able to agree to terms that conform to the recently approved Market Rule updates.

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 scheduled economically via Ontario's real-time markets. The imported energy will target 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, Ontario can call on 500 MW of capacity 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 about the amount of available resources. The Outlook considers two scenarios: a firm scenario and a planned scenario.

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 considered for both scenarios. Submitted generator planned outages are reflected in both scenarios. Table 4-4 shows a snapshot of the forecast available resources, under the two scenarios in normal weather conditions, at the time of the summer and winter peak demands during the Outlook.

Table 4-4 | Summary of Available Resources under Normal Weather

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)	36,928	36,928	36,872	37,971	36,872	38,371
2	Total Reductions in Resources (MW)	10,129	10,129	10,241	10,407	11,024	11,372
3	Demand Measures (MW)	795	795	567	567	795	795
4	Firm Imports (+) / Exports (-) (MW)	-925	-925	0	0	-500	-500
5	Available Resources (MW)	26,669	26,669	27,198	28,132	26,143	27,294
6	Available Resources without Bottling (MW)	27,779	27,779	27,388	28,321	27,361	28,513

Notes on Table 4-4:

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 differs from the Forecast Capability at System Peak shown in Table 4-1 due to the impacts of generation bottling.
6. Available Resources without Bottling: Available resources after they are reduced due to transmission limitations ("bottling").

4.2 Capacity Adequacy Assessment

The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages that have been assessed as of October 25, 2018. The generation planned outages occurring during this Outlook period have been assessed as of November 13, 2018.

4.2.1 Firm Scenario with Normal and Extreme Weather

The firm scenario incorporates all capacity that had achieved commercial operation status as of November 23, 2018.

Figure 4-3 shows reserve above requirement (RAR) levels, which represent the difference between available resources and required resources. The latter equals the demand plus required reserve. The reserve

requirement in the firm scenario under normal weather conditions is met throughout the entire Outlook period.

The IESO's revised outage approval methodology (using the extreme weather scenario with up to 2,000 MW of imports) will be applied for any outages that extend past or begin after May 1, 2019. During these conditions, the reserve is lower than the requirement without reliance on imports for a total of 12 weeks under the extreme weather scenario in 2019 and five weeks in 2020. Under the current outage schedule, the RAR is below the -2,000 MW threshold for one week in early September 2019 and for two weeks in June 2020. 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.

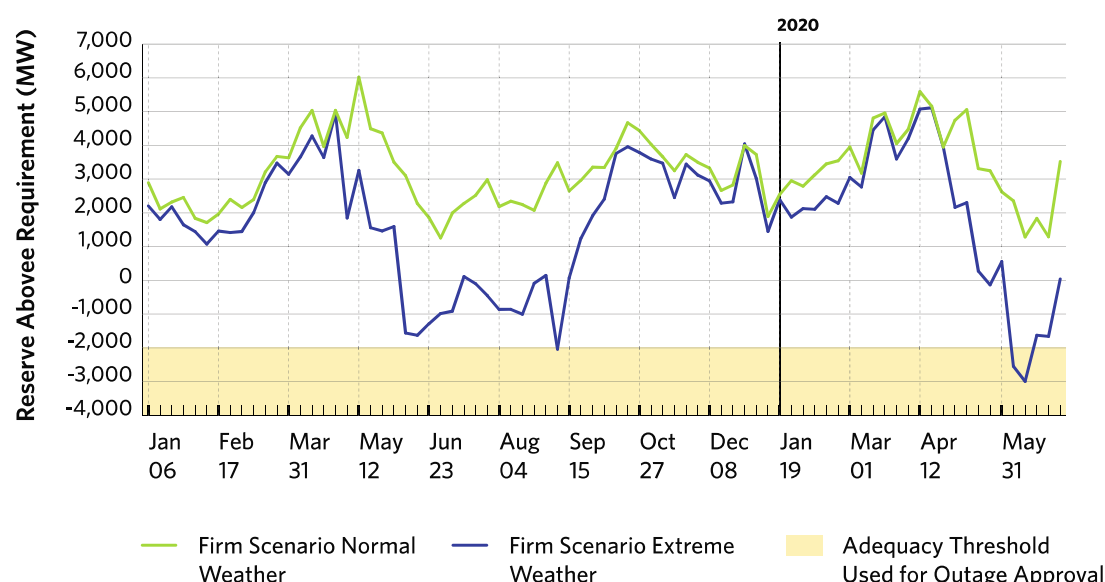


Figure 4-3 | Comparison of Normal and Extreme Weather: Firm Scenario Reserve Above Requirement

4.2.2 Planned Scenario with Normal and Extreme Weather

The planned scenario incorporates all existing capacity plus all capacity coming into service. Approximately 1,500 MW of generation capacity is expected to connect to Ontario's grid over this Outlook period, while approximately 50 MW of generation capacity will reach contract expiry.

Figure 4-4 shows the RAR levels under the planned scenario. As observed, the reserve requirement is being met throughout the Outlook period under normal weather conditions.

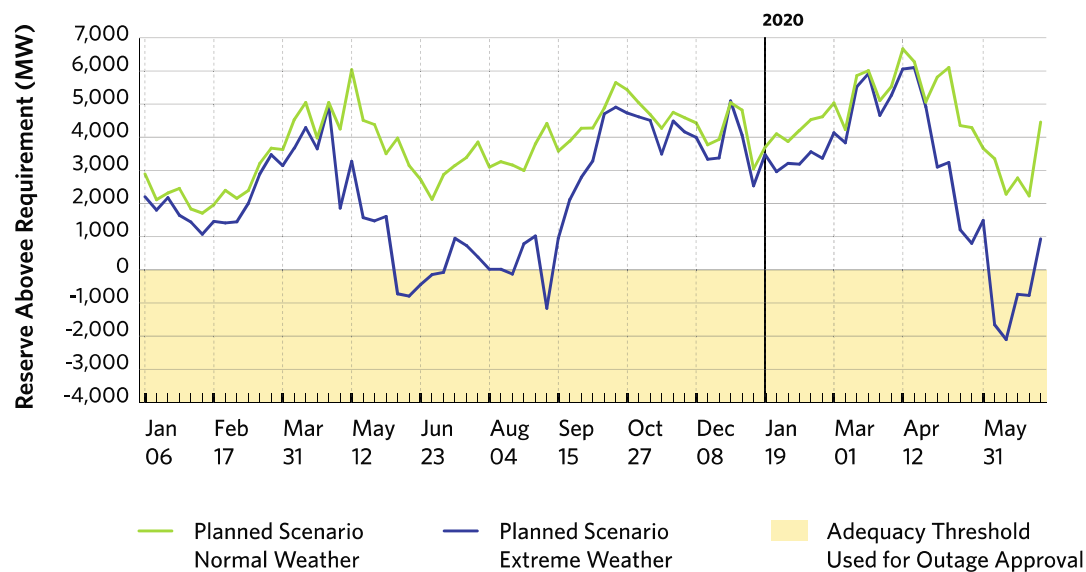


Figure 4-4 | Comparison of Normal and Extreme Weather: Planned Scenario Reserve Above Requirement

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

Figure 4-5 compares the forecast RAR values in the current Outlook with those in the previous Outlook published on September 20, 2018. The difference is primarily the result of changes in planned outages and the expected in-service dates of new resources.

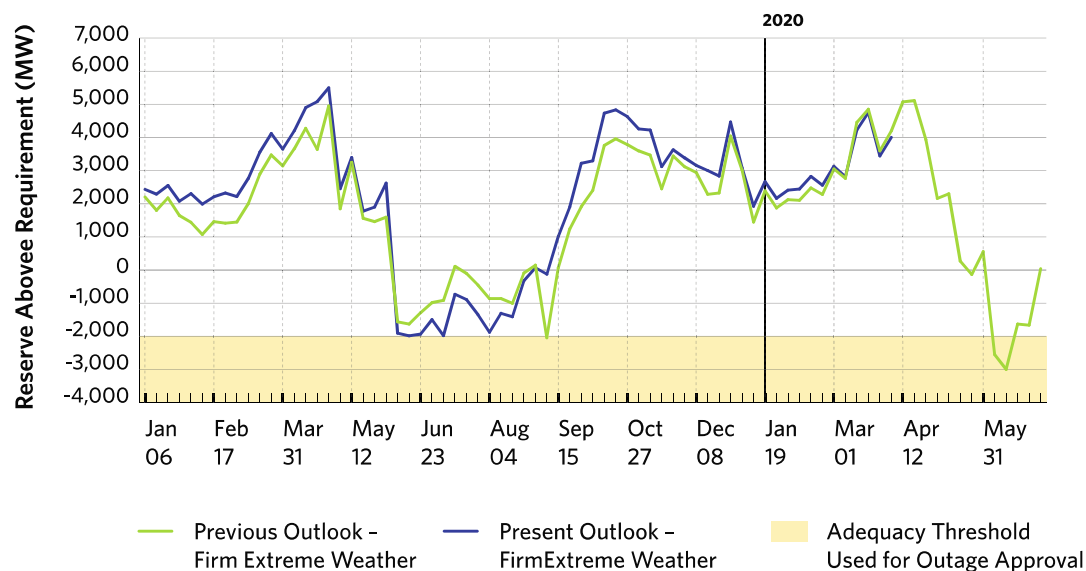


Figure 4-5 | Comparison of Current and Previous Outlook: Firm Scenario Extreme Weather Reserve Above Requirement

Resource adequacy assumptions and risks are discussed in detail in the [Methodology to Perform the Reliability Outlook](#).

4.3 Energy Adequacy Assessment

This section provides an assessment of energy adequacy 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, in Table 4-1 and Table 4-2, pertaining to resources expected to be available over the next 18 months as the capacity assessment. The monthly forecast of energy production capability, based on the energy modelling results, is included in the [2018 Q4 Outlook Tables](#).

For the EAA, only the firm scenario in Table 4-5 with normal weather demand is considered. The key assumptions specific to this assessment are described in the [Methodology to Perform the Reliability Outlook](#).

4.3.2 Results – Firm Scenario with Normal Weather

Table 4-5 summarizes the energy simulation results over the next 18 months for the firm scenario with normal weather demand both for Ontario and for each transmission zone.

Table 4-5 | Summary of Zonal Energy for Firm Scenario Normal Weather

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		GWh	GWh
Ontario	200.4	15,268	200.3	15,258	0.1	456.1	575.6
Bruce	0.9	71	68.5	5,218	67.6	0.9	134.8
East	13.1	997	17.3	1,317	4.2	27.1	64.6
Essa	11.7	889	0.0	3	-11.7	25.0	7.4
Niagara	6.2	472	19.9	1,518	13.7	15.5	43.1
Northeast	15.8	1,204	14.8	1,130	-1.0	26.0	42.0
Northwest	7.3	559	7.1	544	-0.2	12.6	21.5
Ottawa	11.4	872	0.0	3	-11.4	26.6	2.5
Southwest	39.2	2,983	5.4	410	-33.8	90.6	23.7
Toronto	75.5	5,750	59.6	4,542	-15.9	184.4	165.3
West	19.3	1,471	7.5	574	-11.8	47.4	70.8
Ontario	200.4	15,268	200.3	15,258	0.1	456.1	575.6

4.3.3 Findings and Conclusions

The EAA results indicate that Ontario is expected to have sufficient supply to meet its energy forecast during the next 18 months for the firm scenario with normal weather demand, with no anticipated reliance on support from external jurisdictions. The figures and tables in this section are based on simulation of the Ontario power system using the assumptions presented within the outlook to confirm that the Ontario will be energy adequate.

Figure 4-6 shows the percentage production by fuel type to supply Ontario energy demand for the next 18 months, while Figure 4-7 shows the production by fuel type for each month. Exports out of Ontario and imports into Ontario are not considered in this assessment. Table 4-6 summarizes these simulated production results by fuel type, for each year.

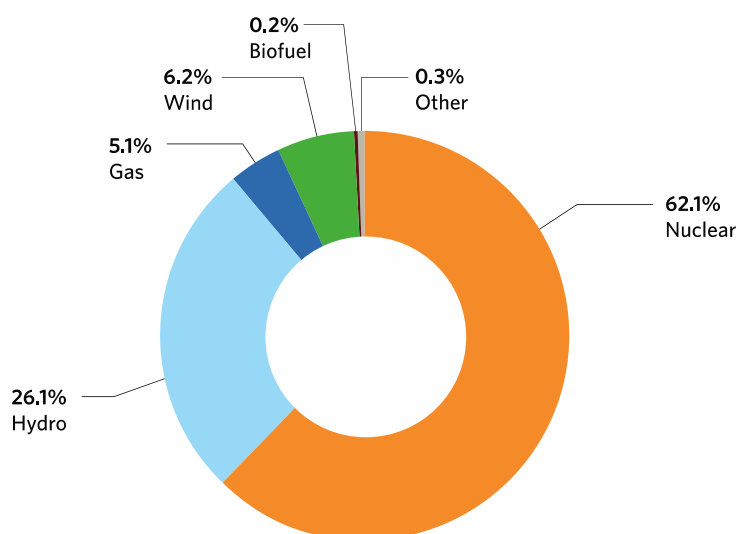


Figure 4-6 | Energy Production by Fuel Type: January 1, 2019 to June 30, 2020

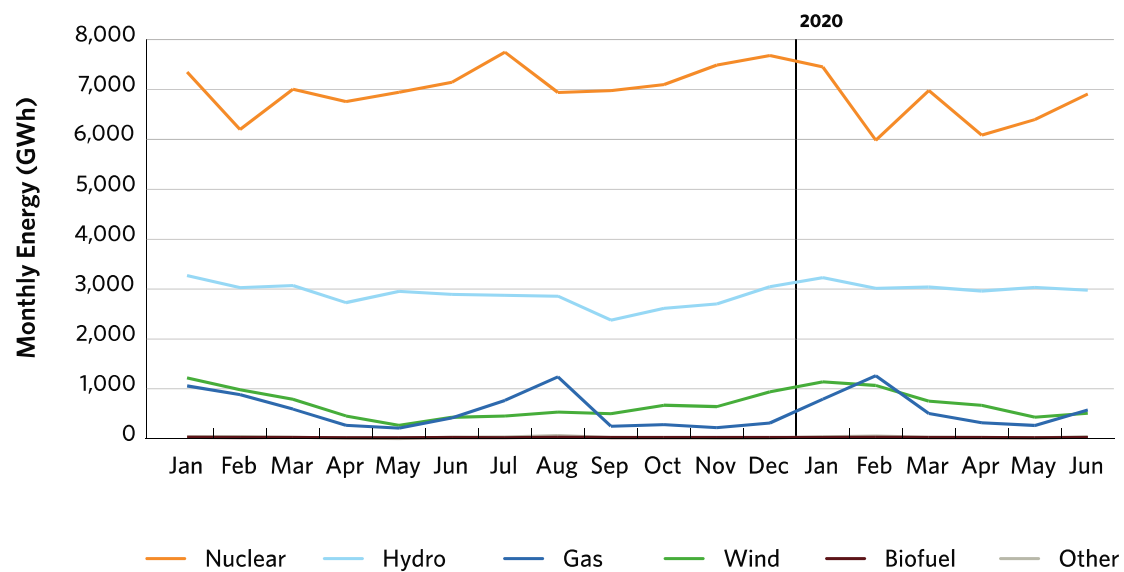


Figure 4-7 | Monthly Energy Production by Fuel Type: January 1, 2019 to June 30, 2020

Table 4-6 | Ontario Energy Production by Fuel Type for the Firm Scenario Normal Weather

Fuel Type (Grid Connected)	2019 (Jan 1 - Dec 31) (GWh)	2020 (Jan 1 - June 30) (GWh)	Total (GWh)
Nuclear	85,568	39,730	125,297
Hydro	34,652	18,494	53,146
Gas & Oil	5,321	3,333	8,653
Wind	7,856	4,472	12,328
Bio Fuel	319	165	484
Other (Solar & DR)	329	199	528
Total	134,045	66,392	200,437

5. Transmission Reliability Assessment

Ontario's transmission system is expected to continue to reliably supply province-wide demand, while experiencing normal contingencies defined by planning criteria for the next 18 months. However, some combinations of transmission and/or generation outages can create operating challenges.

For the purpose of this report, transmitters provide information on the transmission projects that are planned for completion within the next 18 months. A list of such projects is provided in [Appendix B1](#). Only transmission and load-serving projects that are either major modifications or significantly improve reliability are included.

5.1 Transmission Outages

The IESO's assessment of 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 [Methodology to Perform the Reliability Outlook](#). This Outlook contains transmission outage plans submitted to the IESO as of October 25, 2018.

5.2 Transmission Considerations

The IESO assesses transmission adequacy using a 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 in the studies.

Ontario's transmission system is expected to continue to reliably supply province-wide demand while experiencing normal contingencies defined by planning criteria for the next 18 months.

Bruce and Southwest

Hydro One's replacement of aging infrastructure at the Bruce 230 kV switchyard is underway and requires careful coordination of transmission and generation outages. This project is scheduled to be completed by Q4 2020.

Hydro One recently placed a new Bruce Remedial Action Scheme (RAS) in-service. In addition to replacing the existing special protection system, this new RAS features increased functionality to detect and operate for a greater number of system contingencies and configurations. This will facilitate enhanced system operation in the Bruce and Southwest areas.

Niagara

Completion of the transmission reinforcements from the Niagara area into the Hamilton-Burlington area is underway with an expected in-service date of Q2 2019. Once complete, this project will increase the summertime transfer capability from the Niagara region to the rest of Ontario by approximately 800 MW.

West

Significant growth in the greenhouse sector has led to a number of connection requests in the Windsor-Essex region that are expected to exceed the capacity of the existing transmission system in the area. A solution is required as soon as possible. Interim measures and longer-term solutions involving demand management, generation resources and transmission options are being investigated.

East and Greater Toronto Area

Operational challenges due to high voltages in Eastern Ontario and the Greater Toronto Area continue to occur during low demand periods. The IESO and Hydro One are currently managing this situation by removing one of the 500 kV circuits in Eastern Ontario during those periods. To address this issue on a longer-term basis, two 500 kV line-connected shunt reactors will be installed at Lennox TS with a target in-service date of Q4 2020.

Northeast

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. To maintain the required level of service reliability, output of Kapuskasing-area generating facilities may need to be limited. Reinforcements consisting of upgrades to circuit H9K and reactive compensation are being installed with a planned in-service date of Q4 2019 and Q2 2020, respectively.

Interconnections

The failure of the phase angle regulator (PAR) connected to Ontario-New York 230 kV interconnection circuit L33P that occurred earlier this year has impacted the province's ability to import from New York through the New York-St. Lawrence interconnection and from Quebec through the Beauharnois interconnection. This required enhanced coordination with affected parties and more focused management on the St. Lawrence area resources in real-time. PARs are unique pieces of equipment and replacements are not readily available. Replacement options for the unit are currently being investigated jointly with the IESO, Hydro One, New York Independent System Operator and the New York Power Authority.

6. Operability

During the Outlook period, Ontario will continue to experience potential surplus baseload conditions, much of which can be managed with existing market mechanisms, such as exports and curtailment of variable generation. Nuclear curtailments may be required in spring through to early fall 2019.

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

6.1 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, market signals reflect such conditions through lower prices. Resources and activity at the interties respond accordingly to the prices. The resulting outcomes from the market include higher export schedules, dispatching down of hydroelectric generation and grid-connected renewable resources, and nuclear maneuvering or shutdown. For severe surplus conditions, which may affect reliability of the system, the IESO may take out-of-market actions such as manual curtailments of resources and/or imports.

Figure 6-1 shows the nuclear, wind and import curtailments from October 2017 to the end of September 2018.

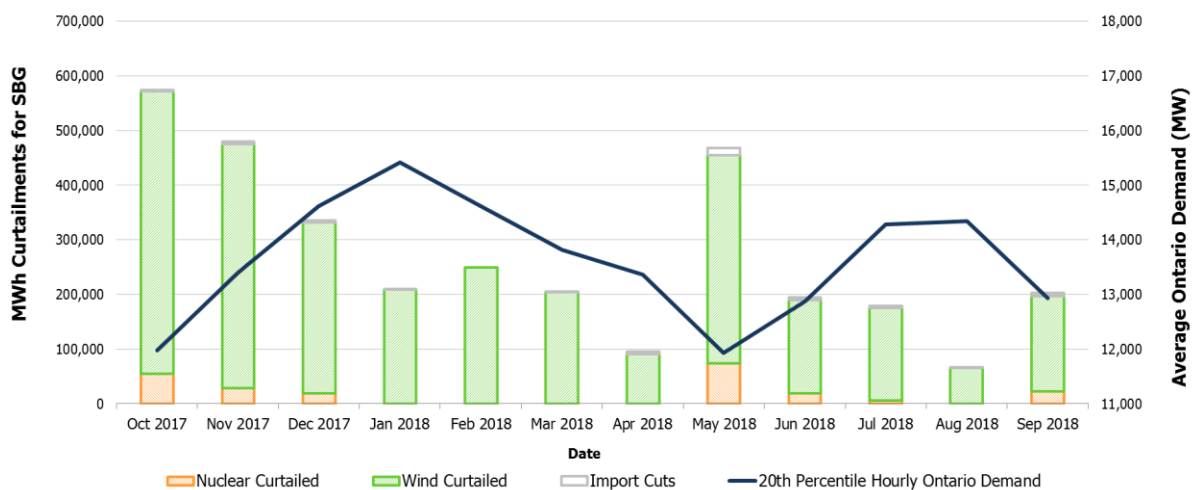


Figure 6-1 | MWh Curtailments versus Ontario Demand

Ontario will continue to experience potential surplus baseload conditions during the Outlook period. Figure 6-2 highlights the periods where curtailment of nuclear generation may be expected.

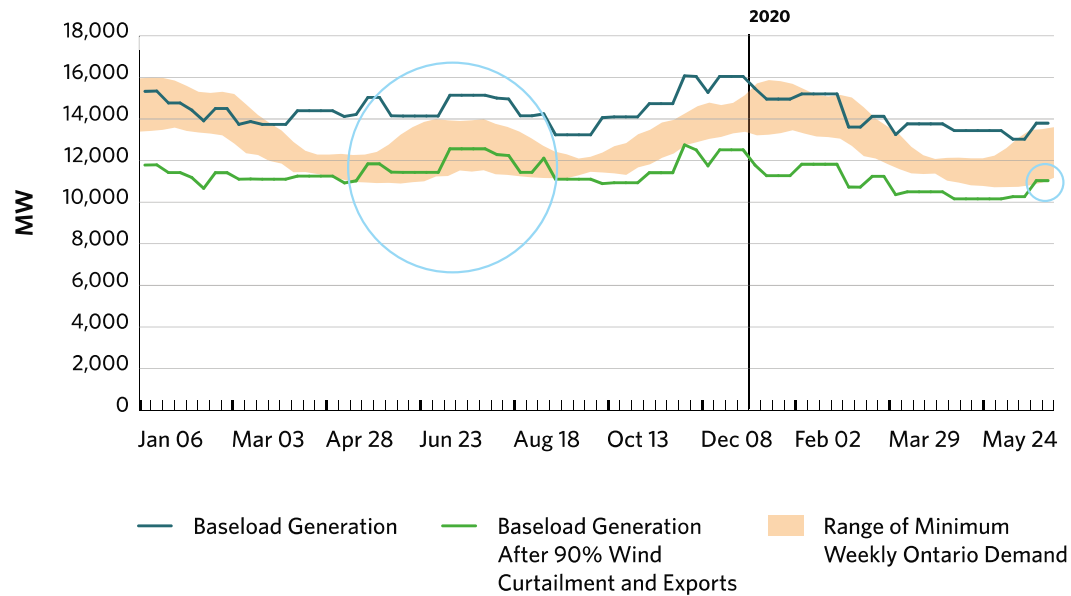


Figure 6-2 | Minimum Ontario Demand and Baseload Generation

Much of the surplus baseload conditions can be managed with existing market mechanisms signaling for exports, and curtailment of variable and nuclear generation. Going forward, as shown in Figure 6-3, existing mechanisms will be sufficient for managing SBG.

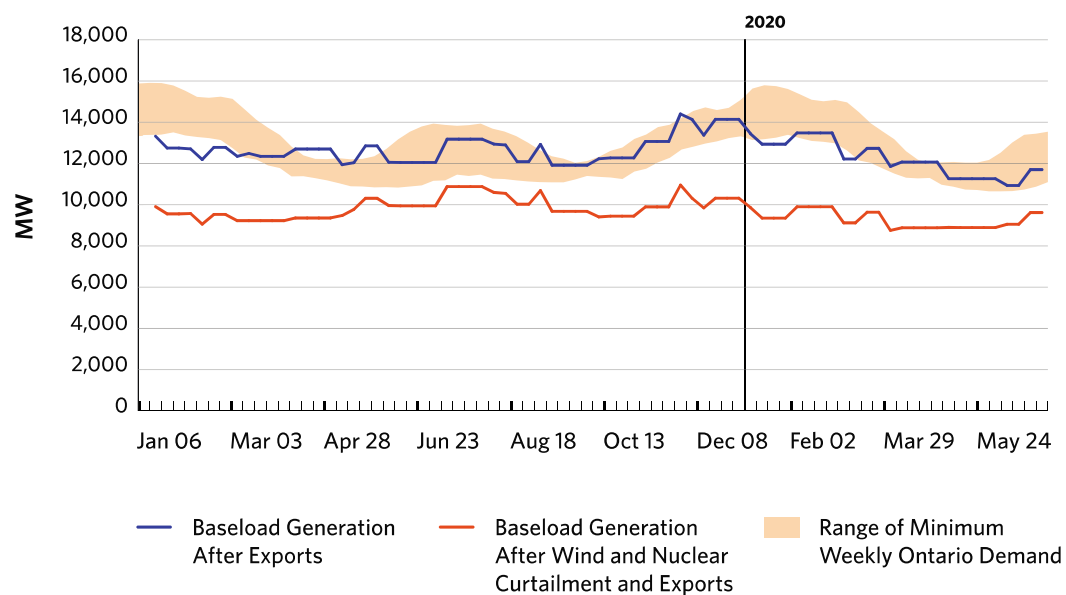


Figure 6-3 | Minimum Ontario Demand and Baseload Generation

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. 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. Figure 6-4 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 Outlook.

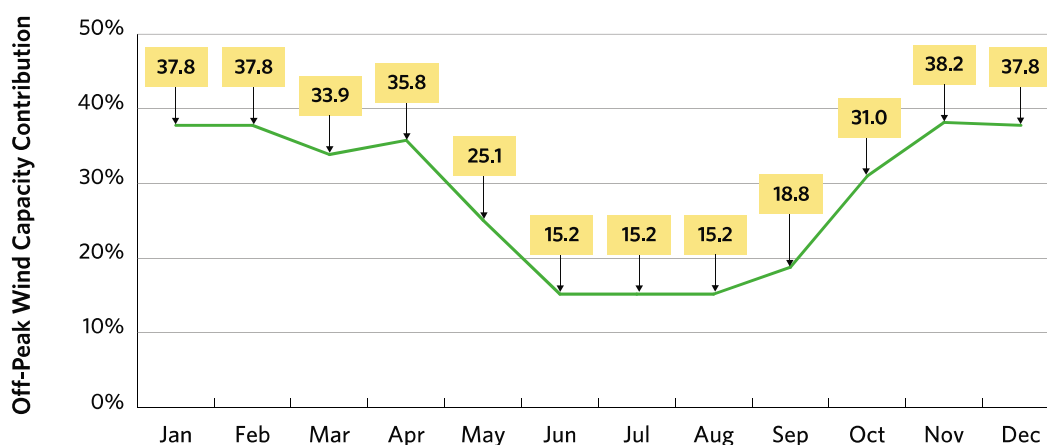


Figure 6-4 | Monthly Off-Peak Wind Capacity Contribution Values

6.2 Distributed Energy Resources and Emerging Technologies

The composition of Ontario's resource mix is changing. There are now over 4,000 MW of distributed energy resources (DERs) in service or under development. Embedded generation, as shown in Table 3.3.6 of the [2018 Q4 Outlook Tables](#), is a subset of DERs. This table only includes generation contracted by the IESO.

DERs offer greater customer choice and present opportunities to optimize overall system investments and provide grid reliability services. The IESO is assessing these opportunities, working with stakeholders through the Grid-LDC Interoperability Standing Committee to understand the impact on the transmission-distribution interface, and exploring areas for further collaboration and data sharing. The IESO needs to ensure it has visibility of DER operations, is able to forecast output over different timeframes, study the impact on reliability, and coordinate their operation to ensure reliability. The Grid-LDC Interoperability Standing Committee's fall workshop focused on the development of a joint Operational Capability Risk Assessment to identify the capabilities required to mitigate risks and take advantage of opportunities. More information is available on the Grid-LDC Interoperability Standing Committee [webpage](#).

The IESO recently completed an operability assessment of its ability to effectively and reliably operate the bulk power system into the future based on real-time operating experiences. The objective of the assessment was to consider the impacts of distribution-connected generation using inverters during and after a transmission system fault, for a study horizon from 2019 to 2025. The IESO studied numerous transmission contingencies to consider the response of load and generators with our improved models to assess the reliability of the bulk power system. The study will be posted on the IESO website in early 2019. The study came to several key conclusions:

- It identified a need to address how inverter-connected generators on a distribution system behave after a transmission system fault. Under certain system conditions, three quarters of DER production in Ontario can trip due to the effects of a transmission fault. This trip could be Ontario's single largest contingency.
- Setting changes to inverter-based resources are a cost-effective way to address reliability concerns. Other transmission system changes may also be used to address reliability concerns. Until these setting changes can be completed, the IESO will develop operating instructions, such as occasional increases to our operating reserve requirement, to ensure reliability of the grid.
- The IESO's assessment of system inertia and frequency response found that there are sufficient traditional rotating generators to support system recovery for the large loss of generation.
- Some unique outage-specific system operating limits may have to be reduced as a result of our improved modelling to ensure reliability for some transmission contingencies.

Implementation of the Phase I and Phase II energy storage programs are well underway, with many of the projects achieving commercial operation or being commissioned. These storage facilities are expected to provide essential grid services, such as regulation, reactive support and voltage control. Eight of the Phase I energy storage projects are operational, with the remaining three projects expected to be in-service by the end of the year. Two of the nine Phase II energy storage projects (totaling 16.75 MW of capacity services) have achieved commercial operation, with the remaining seven expected by November 2019.

7. Beyond 18 Months

The ideal times to schedule additional outages are in early spring, late fall or winter months. In summer 2021 and summer 2023, there is very little opportunity for new outages. In summer 2023, additional capacity may be required in addition to outage coordination to ensure we have sufficient generation to serve Ontario's demand.

The refurbishment of Darlington units and the retirement of Pickering Nuclear Generating Station will create additional outage scheduling challenges for generators located east of the "Flow East Toward Toronto" interface and transmission elements affecting that interface.

7.1 Introduction

New for this issue of the Outlook is an extended planning horizon to give market participants information about resource adequacy and support scheduling and approval of outages during the 42-month period from July 2020 to December 2023. This chapter is intended to inform changes in resource adequacy beyond the traditional 18-month outlook period, along with changes in transmission flow patterns that will make outage coordination and assessments more complex in the future.

Published twice a year in the June and December Outlooks, this section provides a longer-term view of the landscape, with the understanding that the extended timeframe means the values provided are necessarily less precise than those for shorter-term outlooks. To improve the precision of this report, generation and transmission owners should submit their longer-term outage plans to the IESO's outage management system at the earliest opportunity.

7.1.1 Interpretation

The assumptions and assessment approach in this report are focused only on outage management. The IESO identified a potential need for additional capacity to emerge in 2023 and increase through 2025. This suggests that in addition to outage management, interim solutions such as imports and demand response may be required.

Information on global adequacy needs that require investments beyond outage management are provided in the IESO's Planning Outlook, delivered at the [2018 Technical Planning Conference](#). This outlook included nuclear retirements and refurbishments, and facilities reaching end-of-contract terms. A transparent, forward-looking planning process is core to addressing emerging developments and the IESO plans to engage stakeholders in 2019 through its development of an updated Planning Outlook. Access to this information will enable market participants to work collaboratively with the IESO to coordinate planned maintenance outages and help ensure Ontarians continue to have the energy they need to power their homes and businesses.

7.2 Key Findings

Table 7-1 describes key reliability issues expected between July 2020 and December 2023 that may affect outage scheduling or be mitigated by outage rescheduling.

Table 7-1 | Notable Issues or Findings

Issue or Finding	How Issue was Identified	Impact to Outage Management	Additional Information
Periods where outages in the IESO's outage management system should consider rescheduling	Capacity Adequacy Assessment (All Scheduled Outages Scenario)	Generators are advised to consider rescheduling outages to avoid: July 2021 June to August 2023	Section 7.3
Periods where outages not yet in IESO's outage management system should consider scheduling	Capacity Adequacy Assessment (All Anticipated Outages Scenario)	Generators are advised to consider scheduling outages to avoid: June and July 2021 June to September 2023	Section 7.3
Periods where outage management alone cannot resolve capacity adequacy needs	Capacity Adequacy Assessment	Additional capacity likely required in addition to outage rescheduling from June to September 2023	Section 7.3 and 2018 Technical Planning Conference Presentation
Opportunity periods for outages to take place	Capacity Adequacy Assessment	Under all scenarios, there are opportunities for outages to take place from November to April each year	Section 7.3
Flow East Towards Toronto Interface	Recent observations of system conditions	Transfer capability of the Flow East toward Toronto (FETT) interface could be reduced significantly with one or more key transmission elements out of service, particularly when Pickering or Darlington units are out of service	Section 7.5

7.3 Capacity 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 can exist for additional outages when reserves are above required levels, provided other factors such as local considerations, operability, or transmission security do not pose a reliability concern. This assessment is focused solely on outage management. Longer-term information regarding electricity resource needs is provided in the [Planning Outlook, delivered at the 2018 Technical Planning Conference](#).

Uncertainties in the five-year horizon include economic and demographic conditions, achievement of energy-efficiency targets, penetration of embedded generation, weather conditions, timing and completion of transmission and resource projects, as well as the scheduling of planned outages and forced outages. In all cases, these uncertainties increase in relation to the length of the timeframe. Load forecast uncertainty and forced outages were considered probabilistically in these assessments, while other uncertainties were evaluated using a scenario-based assessment of capacity adequacy. These scenarios are described in Section 7.3.1 and the details of those results are available in [Appendix A.11-A.13](#). Further information on the assumptions and inputs are provided in Section 7.4.

7.3.1 Summary of Scenarios Considered

To assess future capacity adequacy, the IESO used a scenario-based approach to compare various risks. The three sensitivities considered are:

- **Outages:** Outages were divided into scenarios based on how the IESO received the schedule, recognizing that outages submitted to IESO's outage management system may have less flexibility to be rescheduled than those submitted annually through the [Generator Information Submittal Form for Reliability Assessments](#) (Form 1230).
- **Project risks:** The planned scenario shows all projects coming into service on time. The delay scenario groups several project risks together by delaying new generation schedules by six months, and the completion date of nuclear refurbishment outages by one year and new transmission equipment by one year.
- **Weather:** The extreme weather scenario combines extreme temperature impacts on demand along with generator ratings at the extreme temperatures.

In this timeframe, outage schedules are less certain and are not all submitted to IESO's outage management system. As schedules become more certain, generator owners will be expected to provide that information in IESO's outage management system. Because of this uncertainty, outages are treated as an additional sensitivity in this longer-term view; in the 18-month timeframe, only project risks and weather are incorporated as sensitivities.

This Outlook for July 2020 to December 2023 presents the results of combining the above sensitivities into three scenarios. Results from these scenarios are shown in the [2018 Q4 Outlook Tables](#) on a monthly basis and discussed in Section 7.3.2.

Table 7-2 | Summary of Scenarios

	Outages	Project Risk	Weather
All Anticipated Outages	All outages submitted in the IESO's outage management system and Form 1230s	Planned	Extreme
All Scheduled Outages	All outages submitted in the IESO's outage management system	Planned	Extreme
Delayed	All outages submitted in the IESO's outage management system and Form 1230s	Delay	Extreme

Table 7-3 shows a snapshot of the forecast available resources, under all scenarios, at the time of the annual peaks during the Outlook.

Table 7-3 | Summary of Available Resources (MW) at Summer Peak

Year	All Scheduled Outages	All Anticipated Outages	Delayed
2020	25,784	25,784	24,906
2021	24,751	24,751	24,751
2022	25,985	25,107	25,107
2023	24,129	24,129	23,251

7.3.2 Capacity Adequacy Findings

The three scenarios previously described show a range of possible outcomes. The “All Anticipated Outages” scenario represents the reference case for the findings, while the other two scenarios bookend what may occur. Figure 7-1 compares the RAR for the “All Anticipated Outages” scenario and for the “All Scheduled Outages” scenario – the difference between the two scenarios is the incremental outages that were submitted to the IESO in the 2018 Form 1230s.

All Anticipated Outages Scenario

The “All Anticipated Outages” scenario factors all outages submitted to CROW and all anticipated outages received in the 2018 annual submission of Form 1230s. This scenario assumes all new generation and transmission comes into service as scheduled.

Under extreme weather, the existing outage plan shows significant periods of risk. As seen below, this fulsome outage plan is close to the threshold for resource adequacy in July 2020. Generators that have outages scheduled in June and July 2021 and from June to September 2023 should consider rescheduling outside summer months, as these are unlikely to be approved. As potential negative reserves during these summers exceed the amount of potential imports that the IESO may rely upon for resource adequacy, all non-critical or short-duration outages should be rescheduled into late fall, winter or early spring.

Generator owners with short-duration outages in July 2020 and from June to September 2022 are advised to continue to monitor future Outlooks for information on the impacts of these outage plans.

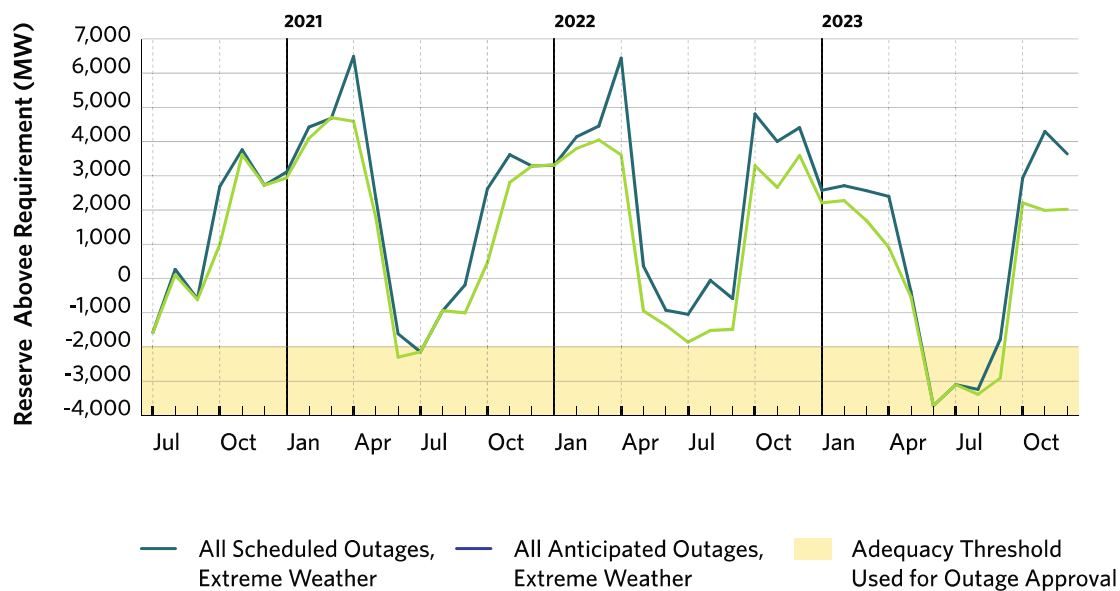


Figure 7-1 | Reserve Above Requirement for All Anticipated Outages and All Scheduled Outages Scenarios

Additional Scenarios

The “All Scheduled Outages” scenario, provided in [Appendix A.12](#) and shown in Figure 7-1, factors all outages submitted to CROW, as of November 13, 2018. This scenario assumes all new generation and transmission comes into service as scheduled. Under extreme weather, the existing outages in CROW will drive the RAR lower than 2,000 MW below the requirement in July 2021 and June through August 2023. Many anticipated outages beyond 2021 are not yet submitted to CROW, making summers 2022 and 2023 optimistic views in this scenario.

The delayed scenario shows a simulation where refurbishment outages and new generation projects are delayed by six months and new transmission lines are delayed by one year. Under normal weather, these additional risks can significantly change the view of capacity adequacy. As a result, the IESO will provide bi-annual updates to the RAR assessment so that market participants can monitor and update their outage plans, should delays occur.

7.4 Inputs and Assumptions

The inputs used for this assessment from July 2020 to December 2023 described in this section are:

- Demand
- Expected installed generation
- Transactions

Further details on the inputs, assumptions and methodology are available in the [Methodology to Perform the IESO Reliability Outlook](#). To reflect the uncertainty in outage schedules, weather, and in-service dates of new resources, several scenarios are employed. These were described in Section 7.3.1.

For resource adequacy assessments that consider periods beyond seasonal planning, it is prudent to adapt some assumptions or methods to reflect additional drivers or uncertainties that are better reflected in long-term adequacy assessments. The differences between the 18-month horizon and the longer-term view are described in Table 7-4 below. IESO assessments may adopt different methodologies or reflect newer/older data, depending on the requirements of each assessment.

Table 7-4 | Methodological Differences from the 18-Month Horizon

Consideration	18 Months	Next 42 Months
Transmission Outages	Considered transmission outage plans that were submitted to the IESO's outage management system by October 25, 2018. Reductions in transmission capacity due to an outage condition are expressed as a change in the base flow/operational limit associated with the interface or interconnection.	Considered transmission outage plans that were submitted to the IESO's outage management system by October 25, 2018. Impacts of outages assessed according to the Transfer Capability Assessment Methodology.
Treatment of New Transmission Equipment	The Planned Scenario assumes that all new transmission equipment is in-service as scheduled. The Firm Scenario considers the transmission system as at the beginning of the Outlook for the duration of the Outlook.	The Planned Scenario assumes that all new transmission equipment is in-service as scheduled. The Delay Scenario considers new transmission equipment in service is delayed by one year.
Treatment of New Generator Resources	The Planned Scenario assumes that all new resources are available as scheduled. The Firm Scenario considers only new resources that have reached commercial operation. The capacity of new generation is the higher of the contracted capacity or the Maximum Generator Capability submitted as part of the Market Registration process.	The Planned Scenario assumes that all new resources are available as scheduled. The Delay Scenario considers all new resources; however, they are delayed by six months from their scheduled start date. The capacity of new generation is assumed to be equal to their contracted capacity.
Generator Outages	Only outages submitted in IESO's outage management system	Outages submitted in the IESO's outage management system and the Form 1230s are considered (see Table 7-2).
Treatment of Resources at End of Contract Term	All resources are removed from the Firm Scenario at the end-of-contract term. Resources that forecast continued operation may be included in the Planned Scenario.	Only resources that have a publicly confirmed retirement date are removed from the assessment.

7.4.1 Demand

Over the forecast period, Ontario energy demand is expected to remain fairly flat with an annual growth rate of -0.2% annually. Much of the growth in Ontario's economy is occurring outside of Ontario's electrically intense industrial sectors. Though those more energy intensive sectors are stable, increased activity is not translating into significant demand growth due to gains in energy efficiency. This trend will continue over the forecast horizon. A strong U.S. economy, low Canadian dollar and low interest rates all help Ontario's export-oriented economy. However, trade disruptions, higher interest rates and increasing prices put current economic expansion at risk.

Both the summer and winter peaks are expected to remain virtually flat over the forecast horizon. This is due to strong downward pressure from peak pricing incentives and increased energy-efficiency savings. With the expansion of embedded capacity plateauing, this downward impact has lessened going forward.

An estimate of an additional 1,400 MW of price-responsive demand is incorporated in the demand forecast. This is a result of price-responsive loads reducing on their own under the ICI. Other demand measures (Dispatchable Loads and resources secured through the DR auction) estimates are forecast based on past performance of these programs, using the same values as in the 18-month horizon.

Table 7-5 | Summary of Forecasted Peaks and Energy

Year	Normal Weather			Extreme Weather	
	Summer (MW)	Winter (MW)	Energy (TWh)	Summer (MW)	Winter (MW)
2020	21,949	21,203	134.3	24,333	22,084
2021	21,942	20,998	133.8	24,268	22,498
2022	21,834	20,976	133.7	24,255	22,477
2023	22,227	20,864	133.7	24,718	22,187

Table 7-6 | Monthly Energy and Peak Demand Forecast

Month and Year	Normal Peak (MW)	Load Forecast Uncertainty (MW)	Extreme Peak (MW)	Normal Energy Demand (GWh)
Jul-20	21,949	838	24,333	11,810
Aug-20	20,920	1,413	23,419	11,436
Sep-20	18,730	781	23,093	10,197
Oct-20	17,321	416	18,303	10,722
Nov-20	19,517	409	21,017	11,196
Dec-20	20,117	528	21,117	12,194
Jan-21	20,998	570	22,498	12,479
Feb-21	19,951	734	21,399	10,918
Mar-21	19,406	531	20,321	11,404
Apr-21	17,399	721	19,768	10,042
May-21	18,330	1,330	21,600	10,232
Jun-21	21,198	754	23,955	11,117
Jul-21	21,942	814	24,268	11,693
Aug-21	20,841	1,362	23,323	11,459
Sep-21	18,652	680	22,990	10,218
Oct-21	17,231	318	18,215	10,698
Nov-21	19,408	607	20,918	11,280
Dec-21	20,222	362	21,026	12,235
Jan-22	20,976	570	22,477	12,430
Feb-22	19,837	734	21,284	10,917
Mar-22	19,326	531	20,241	11,388
Apr-22	17,330	721	19,701	9,926
May-22	18,255	1,330	21,521	10,334
Jun-22	21,101	754	23,867	11,143
Jul-22	21,834	814	24,255	11,589
Aug-22	20,748	1,362	23,213	11,519
Sep-22	18,559	680	22,732	10,194
Oct-22	17,232	318	18,151	10,739
Nov-22	19,291	607	20,806	11,315
Dec-22	20,196	528	20,928	12,196
Jan-23	20,864	570	22,187	12,479
Feb-23	20,120	635	21,186	10,997
Mar-23	19,160	531	20,627	11,523
Apr-23	17,209	471	19,448	10,084

Continued on next page

Table 3.2 – continued

Month and Year	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
May-23	18,103	1,292	21,441	10,270
Jun-23	20,745	754	23,427	10,834
Jul-23	22,227	814	24,718	11,603
Aug-23	20,970	958	24,496	11,798
Sep-23	18,446	781	22,800	10,232
Oct-23	17,004	318	18,271	10,689
Nov-23	19,111	409	20,325	11,133
Dec-23	19,679	690	20,861	12,024

7.4.2 Changes to installed generation

Table 7-7 describes changes to installed generation as a result of:

- Contracted facilities anticipated to enter the IESO-administered markets, listed as “Under Development.” Their capacity is their contracted capacity.
- Modifications to existing facilities, listed as “Under Development.”
- Confirmed retirement of existing facilities.

All resource changes described in Table 4-2 are also included in this assessment.

Table 7-7 | Committed Generation Resources Status

Project Name	Zone	Fuel Type	Planned Date	Delayed Date	Project Status	Capacity (MW)
Northwest Hydro Projects	Northwest	Hydro	2020-Q3	2021-Q1	Under Development	33
Little Long Runner Upgrade	Northeast	Hydro	2020-Q3	2021-Q1	Under Development	8
Pickering A Nuclear Generating Station	Toronto	Nuclear	2022-Q4	2022-Q4	Confirmed Retirement	-1,030
Total						-989

Table 7-8 is provided for information only and lists generation facilities whose contracts expire prior to December 2023. These facilities are assumed to continue operation following their contract expiry in all scenarios of this outlook.

Table 7-8 | Generation Facilities whose Contract Expire during this Outlook Period

Project Name	Zone	Fuel Type	Planned Date	Delayed Date	Project Status	Capacity (MW)
Iroquois Falls	Northeast	Natural Gas	2021-Q4	2021-Q4	Expiring Contract	-131
Lennox Generating Station	East	Natural Gas/ Oil	2022-Q4	2022-Q4	Expiring Contract	-2,100
Thunder Bay Condensing Turbine Project	Northwest	Biomass	2023-Q1	2023-Q1	Expiring Contract	-50
Total						-2281

7.4.3 Firm Transactions

For this outlook, only committed transactions – those where an agreement between two jurisdictions for a set amount of capacity for a period exists – were assumed. The only agreement for this time period is the electricity trade agreement between Ontario and Quebec, whereby Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. As part of this capacity exchange agreement, the 500 MW capacity delivered to Quebec in 2015/2016 winter will be returned to Ontario during summer before September 2030, based on Ontario’s needs. Because the period for this transaction has not yet been confirmed, this capacity was not included in any scenario.

7.5 Transmission Outlook

Flow East toward Toronto (FETT) is the transmission interface that permits the transfer of power to Toronto from generation in the Bruce, Niagara, Southwest and West zones of the province. Transfer capability of the FETT interface could be reduced significantly with one or more key transmission elements out of service.

Outage requests for generation resources located east of the FETT interface or transmission elements that impact the transfer capability of the FETT interface could be denied.

This situation is expected to be more critical as Pickering Nuclear Generation Station units retire and Darlington NGS units are under refurbishment outages. Market participants are encouraged to carefully schedule outages for generation resources located east of FETT and transmission elements that impact FETT transfer capability. Outages that impact FETT are recommended to be scheduled outside of peak demand periods. Submitting outage slips through the IESO’s outage management system early is also advised.

8. Resources Referenced in This Report

The table below lists additional resources, in the order that they appear in the report.

Table 8-1 | Additional Resources

Resource	URL	Location in This Report
Reliability Outlook Webpage	http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook	Introduction
Security and Adequacy Assessments	http://www.ieso.ca/power-data/data-directory	Introduction
2018 Q4 Outlook Tables	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookTables_2018dec.xls	Throughout
Connection Assessments and Approval Process	http://www.ieso.ca/en/sector-participants/connection-assessments/application-status	Assessment Assumptions
Methodology to Perform the Reliability Outlook	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookMethodology2018dec.pdf	Throughout
DR Auction	http://www.ieso.ca/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Demand-Response-Auction	Demand Measures
2018 DR Auction Post Auction Summary	http://reports.ieso.ca/public/DR-PostAuctionSummary/PUB_DR-PostAuctionSummary.xml	Demand Measures
Enabling Capacity Exports	http://www.ieso.ca/en/Sector-Participants/Market-Renewal/Capacity-Exports	Firm Transactions
Ontario Resource and Transmission Assessment Criteria	http://www.ieso.ca/-/media/files/ieso/Document%20Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf	Transmission Considerations
NERC Transmission Planning Standard TPL-001-4	http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf	Transmission Considerations
NPCC Directory #1	https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf	Transmission Considerations
Market Manual 4 Part 4.2	http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-operations/mo-dispatchdatartm.pdf?la=en	Surplus Baseload Generation
Grid-LDC Interoperability Standing Committee	http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Standing-Committees/Grid-LDC-Interoperability-Standing-Committee	Distributed Energy Resources
2018 Technical Planning Conference and Planning Outlook	http://www.ieso.ca/en/sector-participants/planning-and-forecasting/technical-planning-conference	Beyond 18 Months: Introduction
Generator Information Submittal Form for Reliability Assessments	http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/ma-f1230-GenInfo-ReliabilityAssessments.xlsx?la=en	Beyond 18 Months: Capacity Adequacy Assessment
Transfer Capability Assessment Methodology	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/TTCMethodology2018dec.pdf	Beyond 18 Months: Inputs and Assumptions

9. List of Acronyms

CAA	Connection Assessment and Approval
CROW	Control Room Operations Window
DER	Distributed Energy Resource
DR	Demand Response
EAA	Energy Adequacy Assessment
ESAG	Energy Storage Advisory Group
FETT	Flow East Toward Toronto
GS	Generating Station
GTA	Greater Toronto Area
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatts
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
ORTAC	Ontario Resource and Transmission Criteria
PAR	Phase Angle Regulator
RAR	Reserve Above Requirement
RAS	Remedial Action Scheme
SBG	Surplus Baseload Generation
SCC	Solar Capacity Contribution
TS	Transmission Station
TWh	Terawatt-hours
WCC	Wind Capacity Contribution



**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](https://twitter.com/IESO_Tweets)

 facebook.com/OntarioIESO

 linkedin.com/company/ieso