# Annual Planning Outlook

Ontario's electricity system needs: 2024-2043

December 2022

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# Executive Summary

Ontario's economy, projected to see continued development over the coming decades in a number of sectors, is increasingly being driven by decarbonization and electrification. The 2022 APO demand forecast anticipates increased consumption from projects such as new battery manufacturing facilities and mining operations that support decarbonization.

The forecast also illustrates how electrification is changing the shape of Ontario's demand. Accelerated electric vehicle adoption and charging profiles, new building electrification policy, and changes to agricultural sector demand profiles are expected to shift the overall annual system peaks from mid-summer afternoons to mid-winter mid-night periods.

The result is a moderate rise in the average growth of demand, reaching about 1.9 per cent annually compared to 1.7 per cent in the 2021 forecast. This increasing rise, coupled with the impact of nuclear retirements and refurbishments, and expiring generation contracts over the next decade, is contributing to anticipated capacity shortfalls in the mid-2020s.

The IESO has been planning for these needs and over the past two years has made great progress in meeting them — this year's report shows a significant reduction in the mid-2020s gap as a result of actions taken, including the rescheduling of refurbishments, government decisions, and supply procurements through the IESO's Resource Adequacy Framework, including the successful conclusion of this year's first Medium-Term RFP.

The framework continues to successfully procure competitive resources for short, medium and long-term reliability, as with the annual December Capacity Auction. Currently, 4,000 MW of new capacity is also being targeted in the first Long-Term RFP to help address the remaining reliability concerns demonstrated in this report. Final results will be incorporated into next year's planning outlook.

This is a pivotal point for the electricity system, and looking further ahead, it is clear that ensuring reliability, sustainability and affordability in the future depends on maintaining this momentum. New supply must be secured as needs continue to grow and evolve and Ontario sees an expanding reliance on the electricity grid. In addition, as a requirement for more energy production emerges toward the end of the decade, a broader range of supply options could be considered for future procurements.

The APO, along with the *Annual Acquisition Report* (AAR), is a tool that directly informs these types of resource acquisition decisions. The APO is a planning document, using current, confirmed information projecting forward, and giving the sector the most predictive signals possible to serve as a guide for near-term investment decisions and activity.

The AAR aligns strongly with the APO, grounding its acquisition plans in this forecast, and as the pace of change in the electricity sector accelerates, the annual cadence of the APO's forecasts allows the IESO to regularly update data to more accurately reflect the shifting landscape.

This is reflected in this year's increased focus on transmission issues. Transmission will play an essential role in maintaining reliability while the sector transforms, and this report identifies for the first time transmission-related issues looking out over the next two decades on the province-wide system. It also includes a roughly three-year planning road map to signal areas of priority to stakeholders, aiming to better facilitate the participation of industry, developers, municipalities, Indigenous communities, and entrepreneurs in IESO plans.

As the electricity sector continues to transform, the IESO will increasingly incorporate decarbonization efforts into its planning processes and focus on effectively bridging the transition to a decarbonized electricity system and broader economy. The IESO's *Pathways to Decarbonization* report identifies potential opportunities and challenges to consider as Ontario's electricity demand and resource mix evolves. Together with the APO and other reports, it will build on the IESO's ongoing efforts to make the plans and investments today that will help prepare for Ontario's electricity system of the future.

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# 1 Introduction

## 1.1 How to Interpret the Outlook

Grounded in data and market intelligence, the Independent Electricity System Operator's (IESO's) Annual Planning Outlook (APO) identifies future system needs and the factors that influence them, and provides insights into what will be required to prepare for a reliable and affordable electricity future in Ontario. The findings will inform the development of actions described in the IESO's 2023 Annual Acquisition Report (AAR), including providing inputs into the target-setting process for the IESO's upcoming acquisitions.

This outlook covers the period from 2024-2043.

The APO is intended to provide sector participants, governments, municipalities, and Indigenous communities, amongst others, with the data and analyses they need to make informed decisions, and to communicate valuable information to policy-makers and others interested in learning more about the developments shaping Ontario's electricity system.

The assumptions underpinning the APO are based on current system conditions and the best available information about demand, supply, transmission infrastructure and other factors that may influence the results of these studies. However, they do not account for many of the uncertainties in this type of forecast. In particular, the APO does not speculate on changes to Ontario's supply mix, unless they are a result of known government policy or announced actions by the IESO or its stakeholders. In reality, significant change is expected to Ontario's supply mix over the outlook period, and the results presented should therefore be interpreted with this fact in mind. By updating and publishing this analysis annually, the IESO, through the APO, better captures the evolving nature of Ontario's electricity system.

## 1.2 Report Contents

Section 2: Demand Forecast explores long-term demand and walks readers through the changing composition of demand by sector and the resulting effect on overall demand. It also examines the projected impact of conservation programs, building codes and equipment standards and the Industrial Conservation Initiative on reducing that demand.

Section 3: Supply Outlook and Transmission Assumptions assesses the availability of resources over the outlook period. This section also looks at the transmission projects expected to come into service within the outlook period that are considered in the base case for resource adequacy and transmission security assessments.

Section 4: Resource Adequacy compares the demand forecast with anticipated resource performance, taking into account demand forecast uncertainty, transmission constraints and the unavailability of resources due to outages and intermittent generation. This section also examines Ontario's capacity and energy adequacy.

Section 5: Transmission System Reliability explores system needs arising from the requirement to meet transmission planning standards. These needs are referred to as "transmission issues" in this report, and can lead to requirements for local capacity or the need to carry out further bulk system planning.

Section 6: Operability describes some of the operability assessments that are conducted today in order to determine the ability of the system to respond to conditions in real time, and provides the methodology and results of the most recent regulation and black start needs assessments.

Section 7: Integrating Electricity Needs builds on the outcomes and findings of the preceding sections, and summarizes the system needs discussed in Sections 4 and 5.

Finally, Section 8: Outcomes and Other Considerations includes a discussion of marginal resources and marginal costs, the impacts of carbon pricing in Ontario and neighbouring jurisdictions and the expected increase in greenhouse gas (GHG) emissions resulting from decreased nuclear production, increased gas-fired generation and growing demand.

## 1.3 Changes/Updates Since Last Edition

This outlook supersedes the outlook published in December 2021.

Major changes in the demand forecast include developments in societal electrification, including buildings, transportation and industry, as well as forecast updates in the agricultural sector and Conservation and Demand Management programs:

- Building electrification includes the forecasted impacts from the City of Toronto's Toronto Green Standard, municipal permit requirement and planned increase of new-building minimum requirements for energy intensity for 2030.
- Transportation electrification includes the forecasted impacts from the federal government's target for at least 60 per cent of sales of new light-duty vehicles to be zero emissions by 2030. Industrial electrification includes a tally of specific projects, including steel-producer electric arc furnaces, automobile-producer electric vehicle (EV) battery factories and hydrogen electrolysis plants.
- Agricultural sector forecasts include updates to the assumed produce grown in greenhouses in the West of London region and the associated change in seasonal greenhouse operation.
- Conservation program savings forecasts have been updated to include the latest results of the current 2021-2024 Conservation and Demand Management (CDM) Framework as well as savings from the latest federal government–funded programs. The Industrial Conservation Initiative forecast has been updated to reflect the forecasted growth in industrial sector demand over the course of the outlook period.

This current supply outlook includes new and existing resources committed by an IESO planned action or government policy statement at the time of development. It excludes the proposal to further operate the Pickering Nuclear Generating Station (NGS) beyond 2025, which will require approval from the Canadian Nuclear Safety Commission (CNSC).

This outlook also changes the approach to how the IESO assesses the incremental energy needs requirement, marginal costs and marginal emissions. In previous APOs, a proxy resource was used in system modelling as a representational incremental resource to fill in the energy gaps between load requirements and existing and committed resources, and represented a perfect resource that is non-emitting but with a high marginal cost such that it is the final resource to be brought online. This is done as a way to evaluate energy assessments and outcomes of the outlook.

Because the province is seeing a transition toward non-emitting resources with low and/or zero fuel costs it is expected that any future incremental resource would decrease marginal costs. The current assessment therefore no longer uses a proxy resource, but represents the energy requirements of the system "as-is." Marginal costs and marginal emissions are then determined through use of the existing fleet and could be higher or lower than forecasted.

This is also the first APO to present the results of a bulk transmission study that assesses the ability of the transmission system to supply future electricity demand and meet applicable reliability standards and criteria over the outlook period. This assessment therefore identifies future system issues that need to be addressed. It also helps to determine locational constraints on resources and informs the scope of future bulk system plans.

## 1.4 Pathways to Decarbonization

In October 2021, Ontario's Ministry of Energy requested that the IESO evaluate a moratorium on the procurement of new natural gas generating stations in this decade and develop an achievable pathway to phase out natural gas generation and achieve zero emissions in the electricity sector. In response, the IESO conducted the studies presented its Pathways to Decarbonization report. While the APO presents imbalances in demand and supply as system needs and does not speculate about the nature of future resources that may meet those needs, the Pathways assessment presents an illustrative scenario under which Ontario could achieve a net-zero electricity grid while maintaining a reliable system.

The APO and Pathways are closely interrelated: the Pathways assessment builds on the foundational assumptions established in the APO, adding both more aggressive demand growth, based on more intensive electrification in the broader economy, and a suite of non-emitting resources to fill the gaps identified in the Pathways report to replace existing emitting resources at the appropriate time.

## 1.5 Annual Acquisition Report

The Annual Acquisition Report (AAR) is released after the APO, and serves as the primary vehicle to translate planning and operability needs identified in the APO and other system studies into actions to ensure reliability. The AAR aims to provide a clear roadmap for Ontario sector participants, as it provides direction for the marketplace, including a series of planned actions, each corresponding to the initialization of a market action (e.g., executing an upcoming annual Capacity Auction) or discrete procurement activity (e.g., a medium-term request for proposal [RFP]). Planned actions are based on one of the mechanisms specified in the Resource Adequacy Framework. Actions taken since last year's AAR are included in this year's APO as identified in Section 3. The IESO will release its third AAR in 2023, specifying how the future reliability needs identified in this APO will be met.

# 2 Demand Forecast

In this year's APO, electricity demand is ramping up more quickly and growing at a slightly quicker pace than the 2021 forecast, driven primarily by economic development and government policy on climate change. Notable updates include emerging electrification in the building, transportation and industrial sectors, with planned changes in new buildings in the City of Toronto; accelerated federal targets for EVs; and industrial sector electrification projects.

Continuing trends highlighted in prior outlooks include steady growth in the residential and commercial sectors, industrial mining sub-sector growth, the electrification of rail transit and the assumed continued delivery of conservation programs beyond the existing conservation framework period.

Forecasting electricity demand is a challenging exercise as it incorporates uncertainties about future events, including economic growth, changing customer preferences and a rapidly evolving policy environment. The uncertainties associated with any forecast will naturally increase with the length of the outlook period and reflect the interdependencies of underlying assumptions. The demand forecast presented here therefore includes the most current economic and demographic projections, as well as announced projects and policy known of at the time of forecast modeling.

## 2.1 Overview

The long-term demand forecast informs system reliability and investment decisions and sets the context for the APO, AAR and the bulk power system planning process.

Future electricity demand is affected by many factors, including but not limited to the state of the economy, population, demographics, technology, energy prices, input fuel choices, equipment-purchasing decisions, consumer behaviour, government policy and conservation.

Since 2020, Ontario has experienced significant fluctuations in electricity demand as a result of the COVID-19 pandemic and resulting economic recession and recovery, including potential permanent and structural changes to the economy, which were reflected in the 2020 and 2021 APOs.

In this year's APO, the demand forecast continues to reflect the economic recovery and emerging electrification initiatives begun in 2021, leading to higher electricity demand in the short, medium and long term relative to today's levels.

The forecast exhibits strong and steady growth through the end of the 2030s, fueled primarily by industrial sector development in the mid-2020s in mining, steel, EV battery and hydrogen production; agricultural sector greenhouse construction; and transportation sector electrification, before moderating in the early 2040s. Although the exact magnitude and timing of these demands are uncertain, it is clear that the province has entered a period of demand growth. The system is forecast to transition to a winter peak in 2036 from overnight EV charging demand coinciding with the winter system peak, and reduced overall summer peaks from slowing summer demand growth in the agricultural sector.

Overall net energy demand is projected to be 147 terawatt-hours (TWh) in 2024, increasing by an average of almost 2 per cent per year over the outlook period to 208 TWh in 2043, for a total increase of 60 TWh.

Summer and winter peak demands are expected to experience an average growth rate of approximately 1.2 and 1.8 per cent, respectively. Summer peak demand is projected to be 24.6 gigawatts (GW) in 2024, increasing to 30.7 GW in 2043, while winter peak demand is projected to be 22.6 GW in 2024, increasing to 31.5 GW in 2043.

Figure 1 illustrates the forecasted changes in energy demand over the planning horizon. Figure 2 shows summer and winter peak demand.

**Figure 1 | Annual Energy Demand**

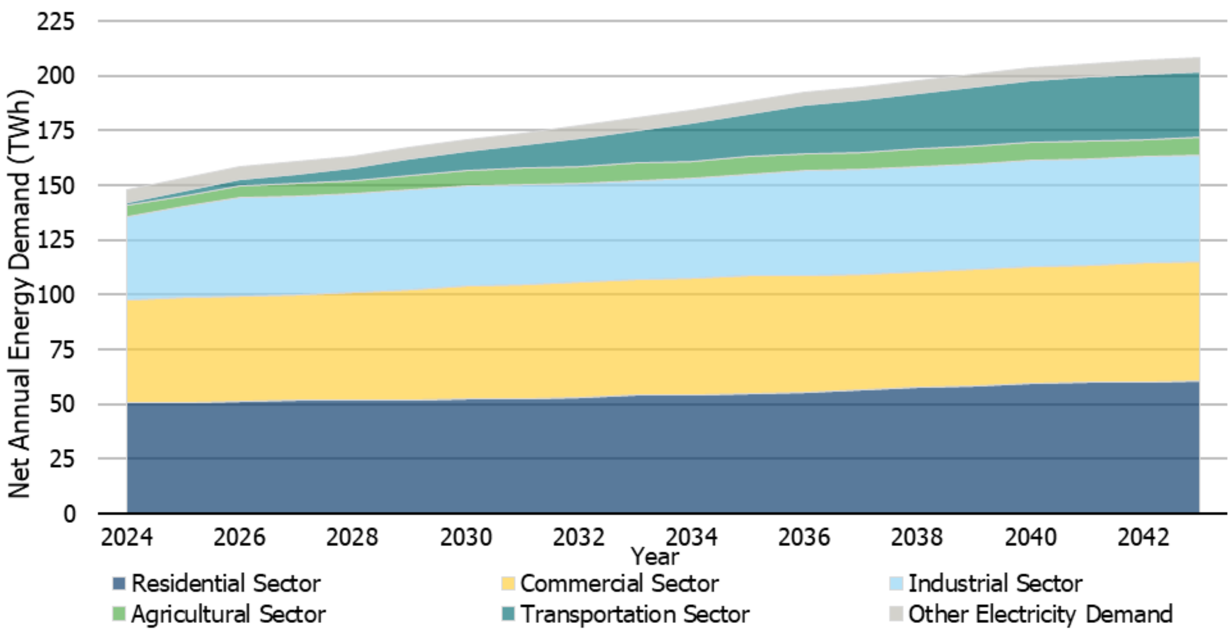
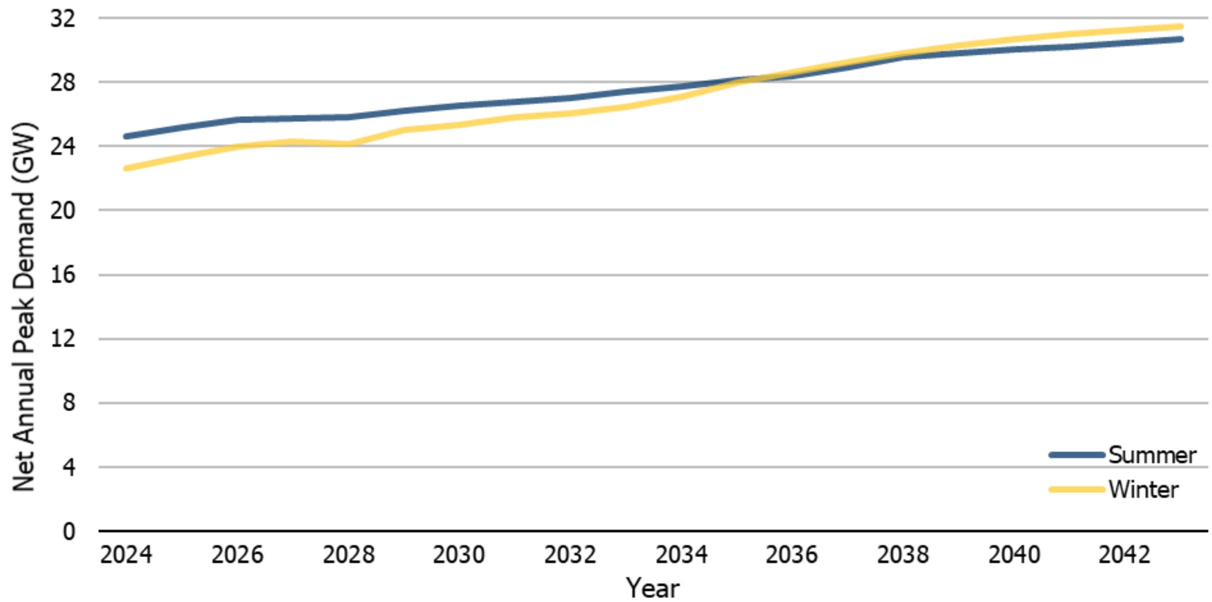


**Figure 2 | Seasonal Peak Demand**




A significant change in system demand forecasted over the course of the outlook period is the change in daily system load profiles attributed to substantial differences in electricity-consumption patterns expected over the course of the next 20 years. A variety of forecasted changes will influence the shape of the daily demand curve – including year-round battery EV charging and an increase in winter-season electric space heating in the City of Toronto – that each result in heightened demand in the evening-to-dawn periods.

Increased agricultural greenhouse consumption will also impact the daily demand profile, as its consumption is greatest between late evening and late morning, with lower consumption in the afternoon and early evening. Additionally, the connection of multiple large industrial facilities will cause the profile to shift upward significantly.

Figure 3 and Figure 4 illustrate the forecasted changes in hourly energy demand in a typical mid-winter and mid-summer business day over the planning horizon.

**Figure 3 | Mid-Summer Business Day: Hourly Profile**

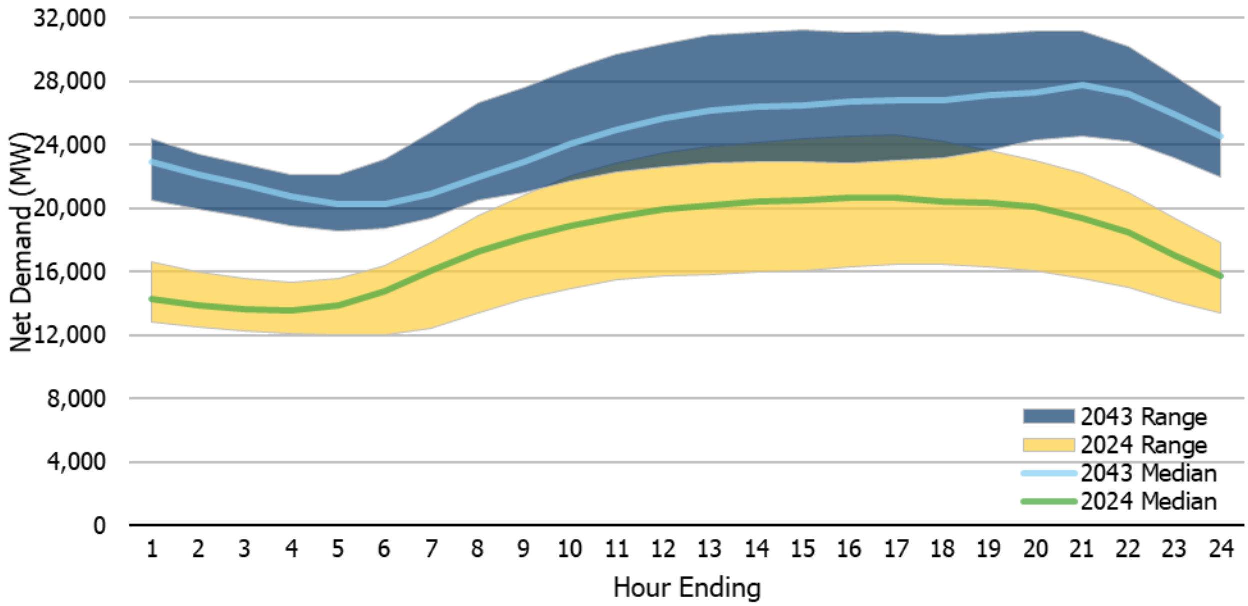
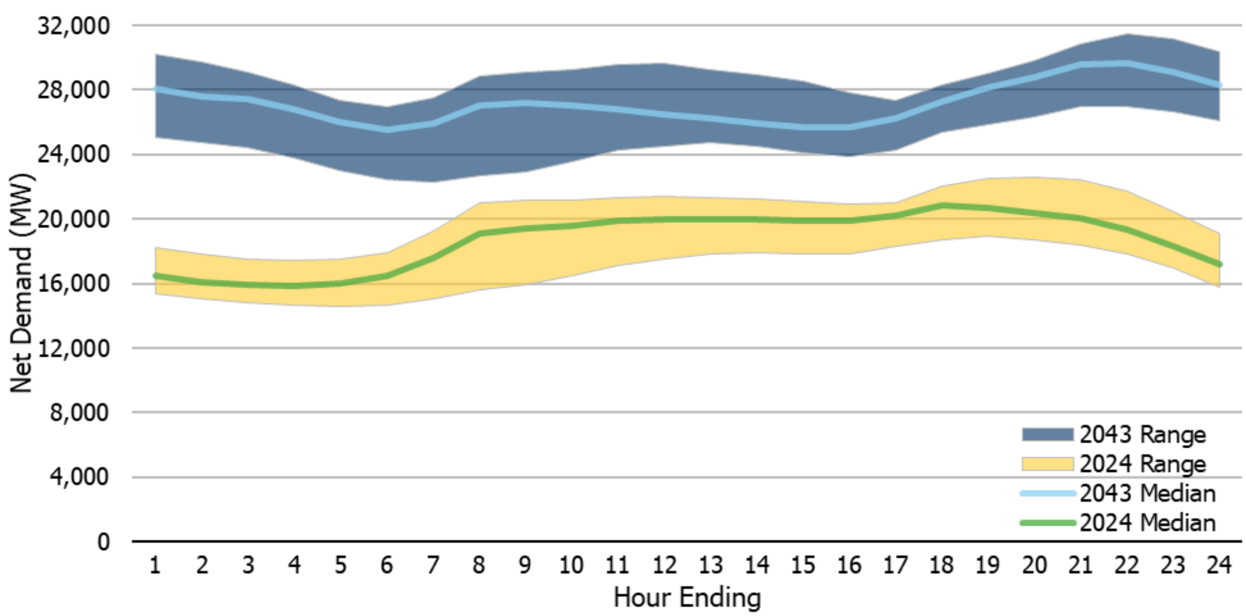


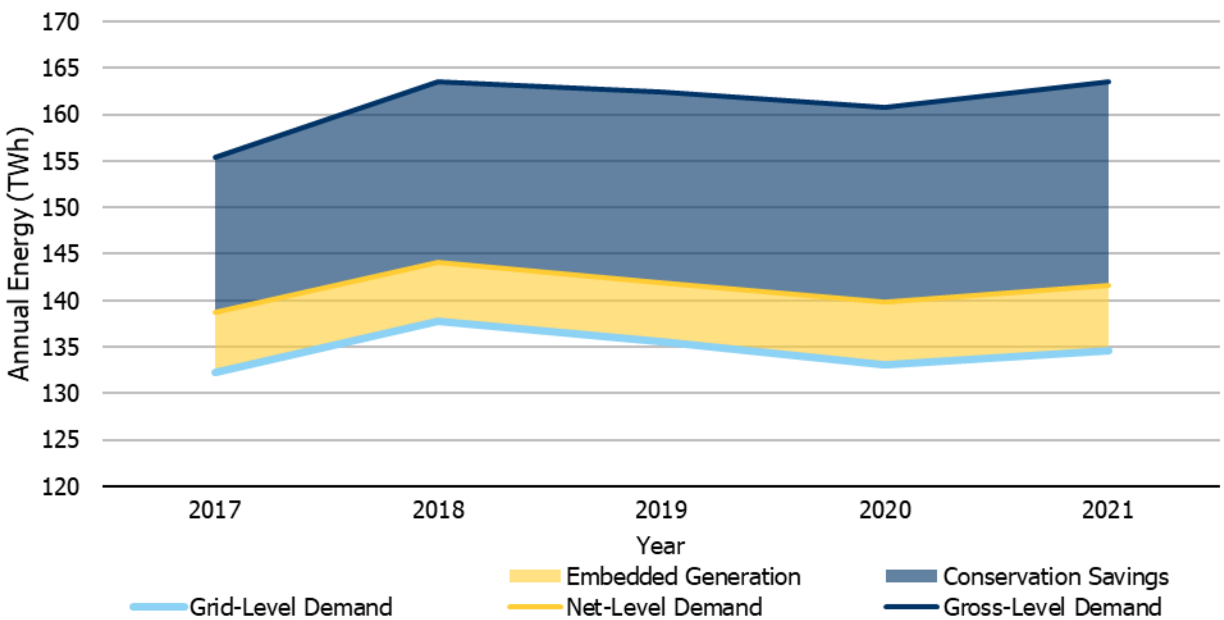

**Figure 4 | Mid-Winter Business Day: Hourly Profile**



## 2.2 Historical Energy Demand

Grid-level demand[1] over the past five years (2017 through 2021) has been mostly flat, ranging between 132 and 138 TWh, as shown in Figure 5.[2] This is primarily the result of changes in the economy, conservation program savings and embedded generation,[3] all of which reduce the need for grid-supplied energy. Embedded generation has provided approximately 6-7 TWh of energy each year.

**Figure 5 | Historical Energy Demand**




**Note**: While historical energy demand has been presented on an actual weather basis and shown at the grid, net and gross levels, the demand forecasts presented are on a weather-normalized basis and at the net level. For more information on weather normalization, see the 2022 APO Demand Forecast Methodology document.

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[1] Gross-level demand is the total demand for electricity services in Ontario prior to the impact of conservation (including programs and regulations), but including the effects of naturally occurring conservation (energy savings that occurs without the influence of incentives or education programs and regulations). Net-level demand is gross-level demand minus the impact of conservation. Grid-level demand is net-level demand minus the demand met by embedded resources. It is equal to the energy supplied by the bulk power system to wholesale customers and local distribution companies.

[2] Historical energy demand presented is actual observed demand based on actual weather and has not been weather normalized.

[3] Embedded generation describes generators that are not registered participants in the IESO-administered wholesale electricity market, that are typically but not necessarily distribution system connected and that reduce demand through the bulk electricity system.

## 2.3 Demand Forecast Summary

Demand forecasting focuses on understanding the causes of future changes in demand by examining demographic, economic, sector and end-use level trends. However, future changes in demand also reflect many dependencies and incorporate uncertainties that increase with the length of the outlook period. The demand forecast presented in this section considers a number of factors: all known demographic projections; sector-level market, economic announcements and trends; the current statuses and projections of large commercial- and industrial sector projects with significant electricity demand; actual grid-connection request queues; and committed policy.

With an emerging transformation of the economy driven by climate change mitigation, by fuel-switching from carbon based fuels to electrification, as well as potential economic development and policy stimulus, a high level of uncertainty is present in the 2022 APO demand forecast. An assessment of these uncertainties and their potential impacts to the forecast is outlined in Section 2.5.

## 2.4 Drivers of Demand

All sectors of the economy – residential, commercial, institutional, industrial, agricultural, transportation and others – contribute to province-wide energy demand. This demand forecast has been developed using sector-level segmentation and corresponding individual assessments.

A projected increase in this forecast's demand is supported by climate change mitigation and economic development policies, stable electricity rates and increasing natural gas rates, including increasing greenhouse gas emission costs, over the outlook period.

#### 2.4.1.1. Residential Sector

Electricity demand from the residential sector is expected to show slow, steady growth over the outlook period. Several factors promote this growth, including progressive immigration policies (tempered by interprovincial emigration) that are contributing to new households, especially in communities adjacent to the Greater Toronto Area; persisting levels of work-from-home and hybrid trends, which result in higher daily household occupancy; the planned implementation of the Toronto Green Standard version 6, municipal permit requirements in 2028 to require buildings constructed in the City of Toronto on or after 2030 to be near zero emissions and continued increases in the adoption of electronics.

Overall, total sector electricity demand is forecast to grow by 20 per cent, from 50 TWh in 2024 to 60 TWh in 2043, an average annual growth rate of 1.0 per cent.

#### 2.4.1.2. Commercial Sector

Ontario's commercial sector electricity demand is expected to be consistent with levels forecasted in the 2021 outlook. Continued slow, steady electricity demand growth continues into the medium term (years 6-10, or 2029-2033) of the outlook period, supported by a continued shift to the digital economy, which affects many sub-sectors, including hybrid office–work models in the office and hospitality sub-sectors, e-commerce in retail and warehouse sub-sectors and meal preparation and delivery services in the restaurant sub-sector. Electricity demand growth is expected to moderate to slower levels in the longer term (years 11-20, or 2034-2043) of the outlook period.

Overall, total sector electricity demand is forecast to grow from 47 TWh in 2024 to 55 TWh in 2043, an average annual growth rate of 0.8 per cent.

#### 2.4.1.3. Industrial Sector

Consistent with the 2021 APO electricity demand forecast, Ontario's industrial sector continues to face significant uncertainty as supply chains adjust to new customer preferences and government policy. Industrial sector level electricity demand is expected to be greater than 2021 APO Reference Scenario levels, with new demand centres emerging in the province's steel-production, EV–production supply chain and hydrogen-production segments.

A number of large industrial projects are included in the forecast. Due to their size, we have included them individually, rather than as part of the aggregated numbers. The forecast for these projects includes high levels of uncertainty in terms of the precise levels of demand and the implementation timelines. Significant electricity demand growth from other projects reflected in the 2021 APO, including northern Ontario mining sub-sector growth and multiple primary metal sub-sector electric arc furnace implementations, have been confirmed with updated implementation timelines and revised demand levels. Industrial sector growth continues to be supported by local production-capability building, economic development, electrification and general GHG emissions reduction trends over the outlook period. Growth continues to be expected in all other sub-sectors, though at a slower rate than previously forecasted.

Overall, total industrial sector electricity demand is forecast to grow from 38 TWh in 2024 to 49 TWh in 2043, an average annual growth rate of 1.3 per cent.

#### 2.4.1.4. Agricultural Sector

Demand for electricity from Ontario's agricultural sector continues to grow, driven by both greenhouse expansion and the proliferation of artificial lighting in greenhouses producing fruits, vegetables, flowers and cannabis, primarily in the West of London area. Growth is primarily in the Kingsville-Leamington and Dresden areas[4] in western Ontario. Sector-level electricity demand growth is lower than forecasted in the 2021 APO as a result of revised greenhouse-output product-mix assumptions, swinging away from cannabis and toward vegetables, with

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[4] The IESO's Need for Bulk System Reinforcements West of London was published to address needs arising from the growing greenhouse demand.

lower electricity demand in the summer season. This will affect annual energy demand and summer-peak demand.

Total agricultural sector electricity demand is forecasted to grow from 5 TWh in 2024 to 8 TWh in 2043, an average annual growth rate of 2.6 per cent.

#### 2.4.1.5. Transportation Electrification

In 2022, the Government of Canada strengthened its climate plan to shift to cleaner fuels in order to decarbonize the transportation sector. As a result, significantly more EVs will be on the road sooner in Ontario. Additionally, several rail transit electrification projects are underway across the province.

Overall electricity demand from transportation electrification is forecast to grow from about 2 TWh in 2024 to 30 TWh in 2043, an average annual growth rate of 17 per cent.

#### 2.4.1.6. Electric Vehicles

The federal government set a mandatory target for all sales of new light-duty cars and passenger trucks to be zero emissions by 2035, with an interim target of 60 per cent by 2030, and the IESO assumes that these targets will be achieved. The number of light-duty EVs (LDEVs) on the road has increased significantly in recent years. At the end of 2021, there were 71,000 LDEVs registered in Ontario, representing 1 per cent of automobiles in the province. Policy measures, improved technology, production maturation and consumer preference contribute to the shift from internal combustion-engine vehicles to EVs. The IESO's LDEV adoption forecast is in line with federal government targets, which project 7.3 million LDEVs in Ontario by 2043.

Other types of EVs, such as electric buses and medium- and heavy-duty EVs, and their associated electricity demand, are also considered and included in the sector-level electricity demand forecast.

Besides EV adoption, which determines the quantities and types of vehicles, fuel efficiency and driving distance also have impacts on electricity demand levels. Peak sector-level electricity demand is largely influenced by charging patterns that need to and can be managed to avoid adding a significant burden on electricity system capacity needs.

#### 2.4.1.7. Rail Transit Electrification

Mass rail transit electrification is also underway in Ontario. GO Transit rail corridors, local light rail transit projects and subway projects are at various stages of planning, construction and operation. Their electricity demands are high-level estimates for this APO and will be updated in future outlooks as more information becomes available.

### 2.4.1.8. Conservation

The electricity demand forecast is reduced as a result of conservation through energy-efficiency programs, a form of resource acquisition, and regulations, a form of market transformation.

### 2.4.1.9. Conservation Programs

Conservation programs continue to play a key role in the power system. Initiatives funded by provincial and federal agencies are underway, achieving energy and peak demand savings and reducing energy and capacity needs.

The IESO-managed 2021-2024 Conservation and Demand Management (CDM) Framework is the central piece of the existing initiatives. It is delivered to consumers under the Save on Energy banner and forecast to achieve 3 TWh annual energy savings when fully complete in 2026. In 2022, the IESO undertook a Mid-Term Review of the Framework to, among other things, review the alignment of the Framework's savings targets and budget with the province's currently forecasted system needs, and report back to the Minister of Energy by the end of 2022.

In the spring, the Minister asked the IESO to, as part of the Mid-Term Review, develop expedited options for additional and expanded CDM programming to help meet forecasted system needs in 2025-2026. As a result, four new or enhanced programs will be launched by the end of Q2 2023. The incremental energy savings of 1.1 TWh from the additional/expanded programs and any additional directives associated with the Mid-Term Review will be reflected in next year's APO.

Other programs funded by the federal government are expected to result in additional electricity savings in Ontario. The Climate Action Incentive Fund and the Green Municipal Fund target the commercial sector to reduce energy consumption and GHG emissions from fossil fuels. The Canada Greener Homes Grant Initiative and the Canada Greener Homes Loan Program help homeowners across the country implement energy-efficiency and GHG emission-reduction retrofits. The electricity demand savings in Ontario from these programs are estimated to be 1.3 TWh by 2024.

Overall, the level of electricity demand savings from all conservation programs in Ontario included in this year's APO forecast fluctuates, remaining at about 15 TWh from 2024 to 2028, and then declining to 10 TWh in 2043 as the electricity demand savings persistence attributable to past conservation programs expire. The demand forecast assumes that the delivery of conservation programs will continue after the current Framework. It is assumed that the annual electricity savings of future program frameworks will be consistent with original levels forecast for the 2021-2024 CDM Framework on a gross-level electricity demand proportional basis. Annual electricity savings forecasts will be updated to include the additional savings from the 2022 CDM framework enhancements emerging from the Mid-Term Review in next year's forecast. The forecast will also be updated when a post-2024 conservation program framework policy decision is made or further directives are received in response to the Mid-Term Review.

#### 2.4.1.10. Conservation Regulations

Conservation regulations, consisting of building codes and equipment standards, are an effective energy-efficiency tool and have a relatively high level of certainty. These savings estimates are based on expected improvements in codes for new and renovated buildings and the regulation of minimum efficiency standards for equipment.

The IESO estimates electricity demand savings attributable to codes and standards by comparing the demand forecast at the gross level to the demand forecast adjusted for the impacts of regulations. Most of the savings from improved codes and standards will be realized in the residential and commercial sectors. The conservation regulations electricity demand savings forecast is largely the same as in the 2021 APO, as are gross-level demand and regulations. Going forward, as changes to regulations are announced, the IESO will analyze its impacts and include them in the latest demand forecast and outlook.

Overall, electricity demand savings from codes and standards are forecast to grow to 7 TWh in 2043 from base-year levels.

#### 2.4.1.11. Industrial Conservation Initiative (ICI)

The ICI is a form of demand response that enables large customers (known as Class A customers) to reduce their electricity costs by curtailing electricity consumption during periods of peak demand.

The IESO forecasts future ICI response based on observations from year 2021 and stratifies forecasted response profiles in four different profiles/levels: 1) summer season top 5 system peak day; 2) summer season second top 5 system peak day; 3) winter season top 5 system peak day; and 4) winter season second top 5 system peak day; that account for different system peak hours across seasons. In 2024, for both the summer and winter the top-five system peak-day, system peak-hour response is expected to be 1,300 MW, and the second top-five system peak-day, system peak-hour response is expected to be 650 MW. Along with growing industrial sector demand, ICI response is expected to grow over the outlook period, to 1,660 MW and 830 MW for both summer and winter, top-five and second top-five system peak-day, system peak-hour response, respectively, in 2043.

The IESO expects that ICI drivers, including customer ICI program investment and global adjustment levels, will inevitably change over time, and ICI impacts on the demand forecast and ICI forecast methodology will be reassessed on an annual basis.

#### 2.4.1.12. Other Electricity Demand

This demand forecast accounts for all electrical energy and peak demand in the province. However, certain areas of demand do not fall under any of the previously discussed sectors and are therefore classified as "other." These include:

- The connection of remote communities
- Electricity generators[5]
- Street lighting
- Municipal water treatment

Remote community connections over the course of the outlook period will have their respective demand forecasts included into explicit sectoral level demand forecasts and reflected in the APO as they are connected.

Overall, "other sector" electricity demand is unchanged from the 2021 APO and is forecast to grow from 5.5 TWh in 2024 to 6.2 TWh in 2043, an average annual growth rate of 0.6 per cent.

## 2.5 Demand Forecast Uncertainties

The 2022 APO demand forecast presented in this section incorporates the latest available information, and makes projections based on:

- Economic, demographic and post-pandemic impact projections;
- Announcements and statuses of industrial sector projects, including the characteristics of distinct units with significant demand and sensitive implementation timelines;
- Committed climate change mitigation, economic development, energy and conservation policies;
- The state of the electricity sector, including committed policies; and
- Customer preference trends.

The drivers of the electricity demand forecast are constantly evolving, including potential policies in proposal development or in pilot phases, such as potential future time-of-use rates and other alternate pricing models and therefore the IESO continues to update its electricity demand forecast on an annual basis and to reflect updates in each year's APO.

[5] Electricity generators such as gas, oil and nuclear generating stations can experience electricity demand when 1) commencing operation and 2) when not in operation — e.g., a facility could have electricity demand for lighting and heating, ventilation and air conditioning loads.

# 3 Supply Outlook and Transmission Assumptions

Ontario's supply mix will undergo significant change over the next two decades as the available capacity from the nuclear fleet continues to be impacted by refurbishments and retirements, and resources reach contract expiry, with uncertainty as to whether they will continue to participate in the market. In the near term, we see increases in available generation in response to actions taken from previous outlooks by the government and the IESO.

A number of transmission projects are also expected to come into service within this decade, contributing to the resource adequacy and transmission assessments of this outlook.

This section describes the availability of the province's existing supply resources over the outlook period, as well as bulk transmission system assumptions used to inform the transmission assessment in this APO.

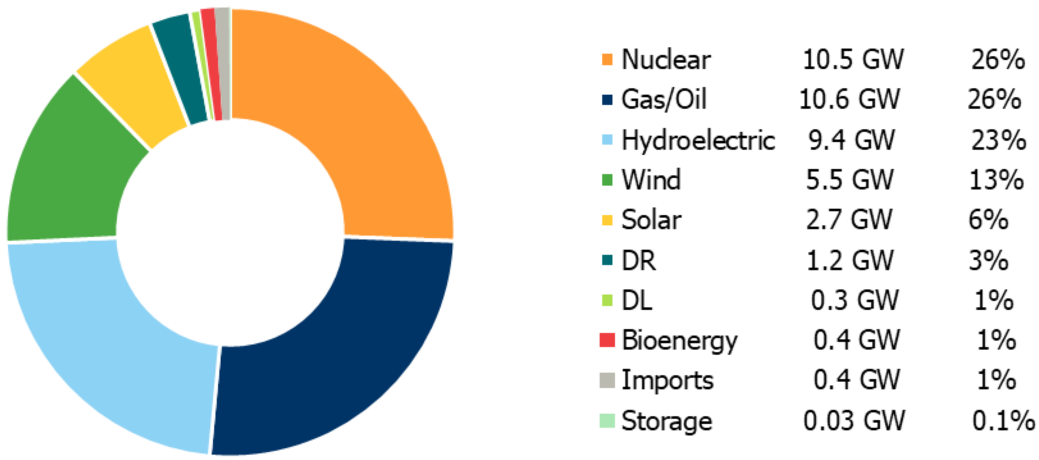
## 3.1 Installed Capacity, 2023

Ontario has 41.2 GW of installed capacity, which is made up of a diverse mix of resources, as shown in Figure 6.[6]

Ontario has a diverse mix of resources and in 2023, the installed capacity by fuel type was nuclear at 10.5 gigawatts, gas at 10.6 gigawatts, hydroelectric at 9.4 gigawatts, wind at 5.5 gigawatts, solar at 2.7 gigawatts, demand response at 1.2 gigawatts, dispatchable loads at 0.3 gigawatts, bioenergy at 0.4 gigawatts, import at 0.4 gigawatts, and storage at 0.03 gigawatts.

[6] This data includes both transmission and distribution-connected resources, either market participants and/or contracted by the IESO. For further information, please see the 2022 APO Supply, Adequacy and Energy Outlook module.

**Figure 6 | 2023 Installed Capacity by Fuel Type**[7]




## 3.2 Supply Outlook

This section provides an understanding of the basis of the supply outlook. With nuclear resources providing a large portion of Ontario's capacity and energy needs, Ontario's supply outlook is impacted by the refurbishments of the nuclear assets, and this section explores the current view of the nuclear retirement and refurbishment program and how it impacts the supply outlook. Further, resources reaching contract expiry also impact the future supply outlook. Given the uncertainty of resource availability post contract expiry, this APO explores two scenarios that look at different assumptions for availability of resources.

The two supply cases are presented following the IESO's most recent AAR. These cases include both existing and committed resources (i.e., resources that are expected to come online over the study horizon) that have been identified by an IESO planned action or provincial government policy statement at the time of report development. These include:

- Capacity from the IESO's first Medium-Term Request for Proposal
- A 300 MW Small Modular Reactor at OPG's Darlington nuclear site
- Hydro Quebec Capacity Sharing Agreement, utilizing the 500 MW capacity imports in summer of 2026
- Government policy on biomass extensions

[7] Both transmission- and distribution-connected resources that are reported to IESO (e.g., embedded generation) are included in the capacity assessment. Imports include both system-backed imports from the 2021 Capacity Auction and assumptions on non-firm imports. Non-firm imports are assumed to be included as part of the total installed capacity.

- Government policy on small hydroelectric program
- 2022 AAR Capacity Auction forward guidance targets
- Bilateral negotiations for Lennox GS and Brighton Beach GS

Case 1 reflects resources until their contract/commitment period ends.[8] It defines system needs where some of which can be met by existing resources. Case 2 includes the resources in Case 1, and assumes that these resources continue to be available post-contract/-commitment expiry for the duration of the study period. Case 2 helps identify minimal new incremental resources that will be needed to meet system needs.

Within the cases, and due to the timing of this report's data analysis, Pickering NGS Units 5-8 are assumed to retire by the end of 2025 and therefore do not reflect the Ministry of Energy announcement made on September 29 regarding continued operation and refurbishment. The proposal also requires CNSC approval. The supply cases also do not include resources expected through the expedited long-term procurement, long-term 1 RFP and same-technology upgrades procurements, targeting of approximately 4,000 MW of capacity. Once the successful proponents are announced, these resources will be reflected in subsequent APO outlooks. The hydroelectric fleet is assumed to be available for the duration of the outlook in both cases, given its long technical life.

The supply outlook is shown for both installed capacity, or a resource's maximum output, and effective capacity at summer and winter peak, taking into account factors such as fuel availability, ambient conditions and/or outages (see Table 1). This makes effective capacity a more meaningful measure of a resource's ability to meet reliability needs.

**Table 1 | Ontario's Summer 2023 and Winter 2023/2024 Effective Capacity**

| Fuel | 2023 Installed GW | 2023 Summer Effective GW | 2023/24 Winter Effective GW |
|---|---|---|---|
| Nuclear | 10.5 | 8.4 | 10.1 |
| Gas/oil | 10.6 | 8.7 | 9.4 |
| Hydroelectric | 9.4 | 6.5 | 7.3 |
| Wind | 5.5 | 0.6 | 1.6 |
| Solar | 2.7 | 0.7 | 0 |
| DR[9] | 1.2 | 0.8 | 0.6 |
| DL | 0.3 | 0.2 | 0.1 |

[8] Case 1 assumes that hydroelectric resources are available post-contract expiry.

[9] Demand response (DR) and dispatchable loads (DL) reflect the results of the IESO's 2021 Capacity Auction.

| Fuel | 2023 Installed GW | 2023 Summer Effective GW | 2023/24 Winter Effective GW |
|---|---|---|---|
| Bioenergy | 0.4 | 0.4 | 0.4 |
| Imports | 0.4 | 0.4 | 0.2 |
| Storage[10] | 0.03 | 0.03 | 0.03 |
| Total | 41.2 | 26.8 | 29.7 |

Figure 7 shows the total installed capacity by fuel type for the outlook period for Case 1. Case 1 assumes that contract/commitments are not reacquired except for hydroelectric resources. Installed capacity decreases from about 41 to 29 GW in the next decade, before levelling off at approximately 23 GW through 2043.

**Figure 7 | Installed Capacity (Case 1)**

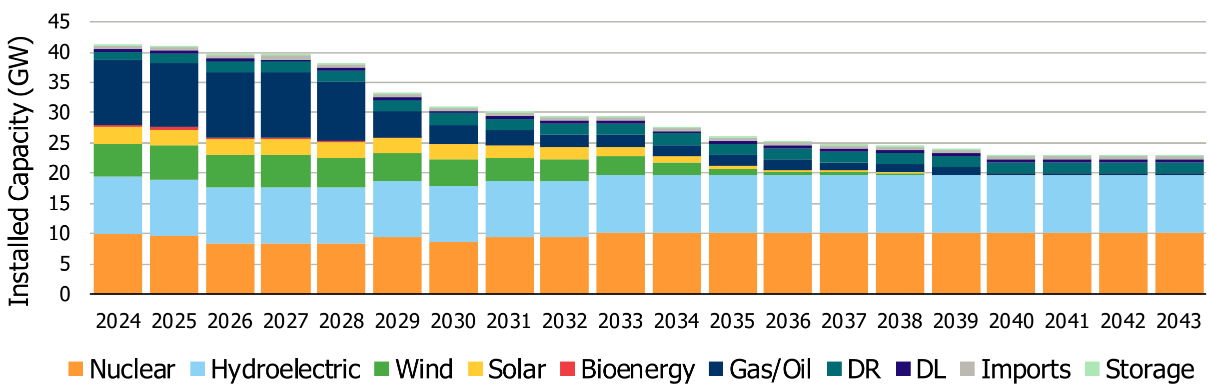



Figure 8 shows the total installed capacity by fuel type for the outlook period for Case 2, which assumes the continued availability of resources following the end of their contract term or commitment. Installed capacity varies between 40 and 42 GW in the next decade, before levelling off at 42 GW through 2043.

[10] Includes lithium-ion battery storage through the 2021 Capacity Auction.

**Figure 8 | Installed Capacity (Case 2)**

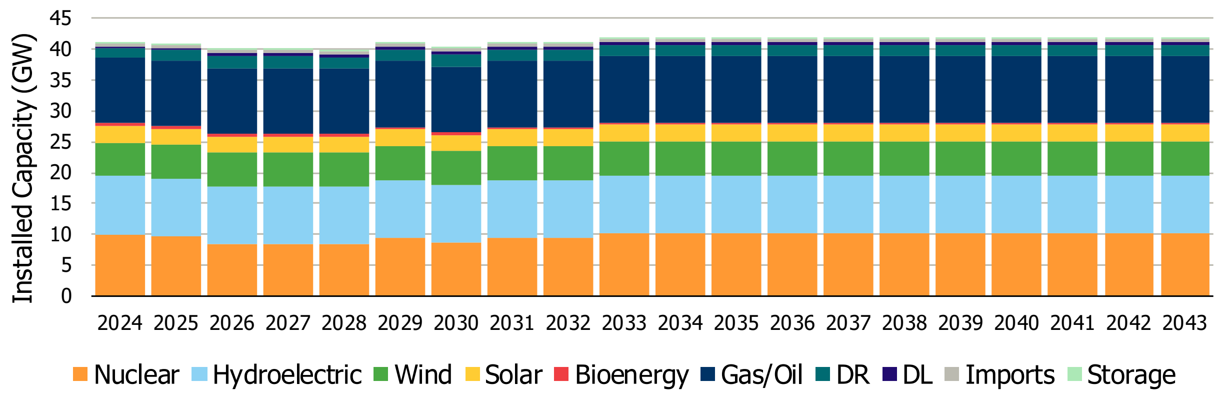



Figure 9 shows the summer effective capacities by fuel type for the outlook period in Case 1. Summer effective capacity varies between 29 and 22 GW during the 2020s due to the refurbishment of the nuclear fleet, and then levels off at about 18.6 GW through 2043 due to contracts expiring.

**Figure 9 | Summer Effective Capacity (Case 1)**

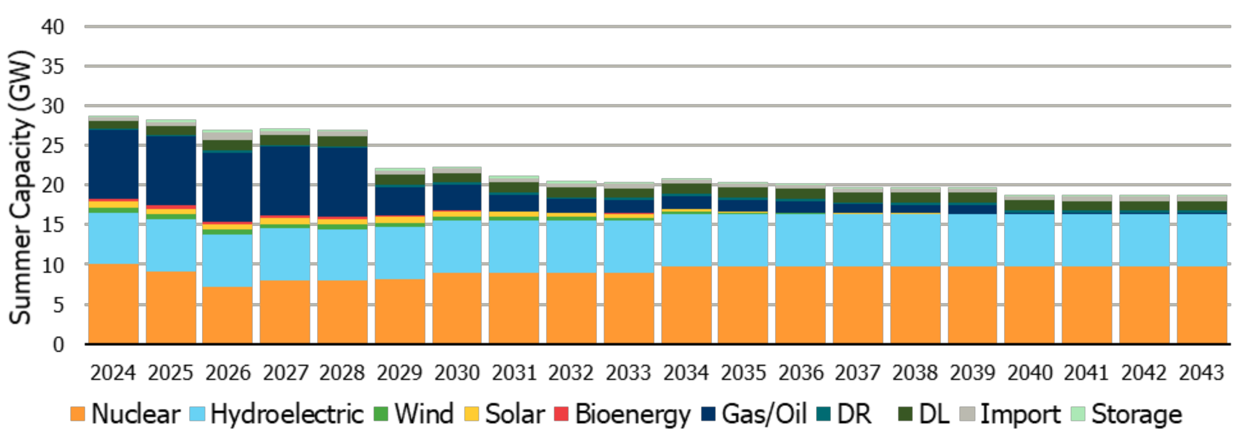



Figure 10 shows the summer effective capacities by fuel type for the outlook period in Case 2. Summer effective capacity varies between 27 and 29 GW during the 2020s, due to the refurbishment of the nuclear fleet, and then levels off at 29 GW through 2043.

**Figure 10 | Summer Effective Capacity (Case 2)**

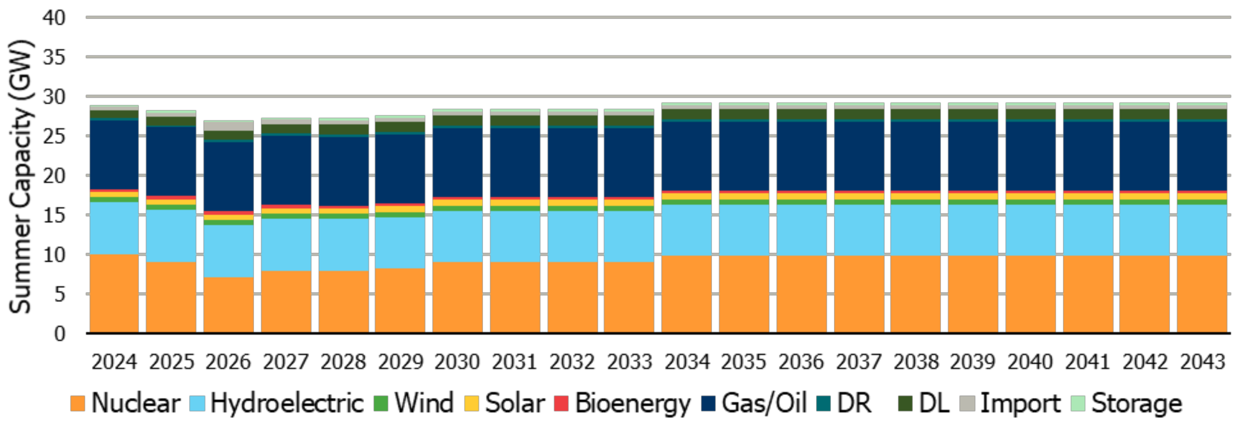



Figure 11 shows the winter effective capacities by fuel type for the outlook period in Case 1. Winter availability of the fleet ranges between 21 GW and 30 GW and then levels off at about 17 GW through 2043 due to contracts expiring.

**Figure 11 | Winter Effective Capacity (Case 1)**

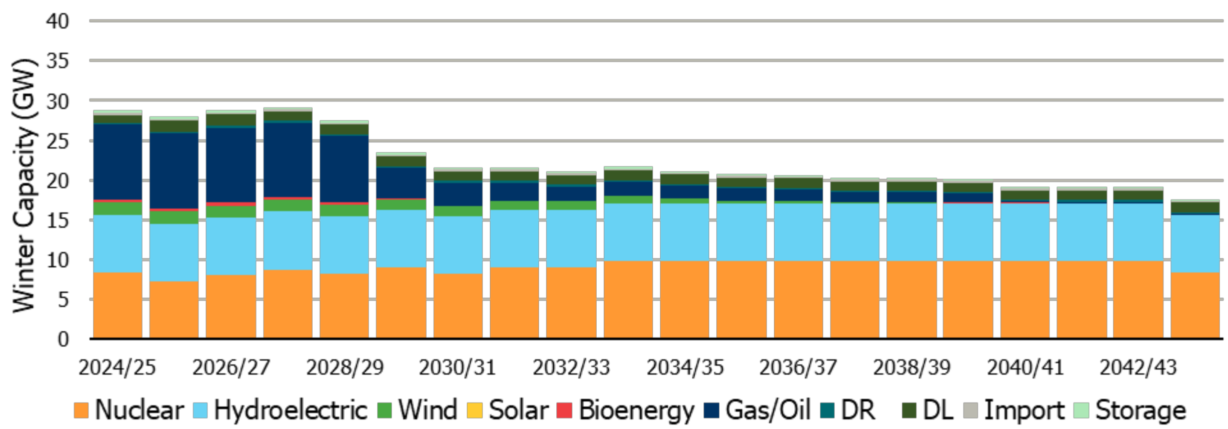
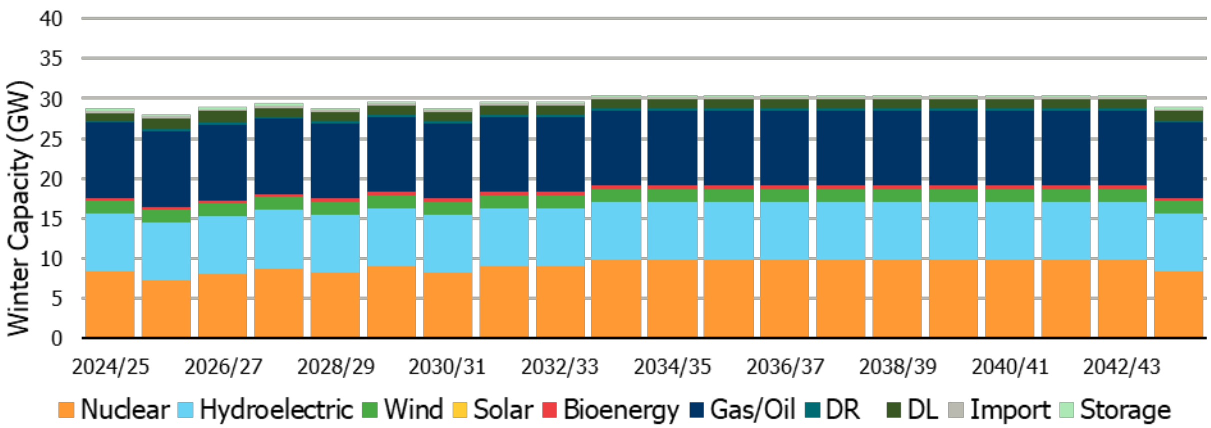



Figure 12 shows the winter effective capacities by fuel type for the outlook period in Case 2. Winter availability of the fleet ranges between 28 GW and 31 GW, and then levels off at 29 GW through 2043.

Figure 12 | Winter Effective Capacity (Case 2)




### 3.2.1.1. Nuclear Refurbishments and Retirements

Throughout the 2020s, Ontario's electricity system will experience a significant change in the available capacity of its nuclear fleet. Various refurbishments will result in long-term outages at Darlington NGS and Bruce NGS, and will increase resource needs. This assessment assumes the retirement of Pickering NGS by the end of 2025. Its proposed nine-month extension to September 2026, if approved by regulators, would add reliability assurance and reduce system emissions through the summer of 2026.

The nuclear refurbishment and retirement schedule has remained unchanged (see Figure 13) from last year's outlook, except for the following. These changes provided positive impacts on the ability to provide adequacy:

- Bruce NGS: G3 unit returns to service later; G5 unit refurbishment is shifted later; G8 unit refurbishment is shifted later
- Darlington NGS: G3 unit returns to service earlier; G4 unit refurbishment is shifted earlier

**Figure 13 | Nuclear Refurbishment and Retirement Schedule**[11]

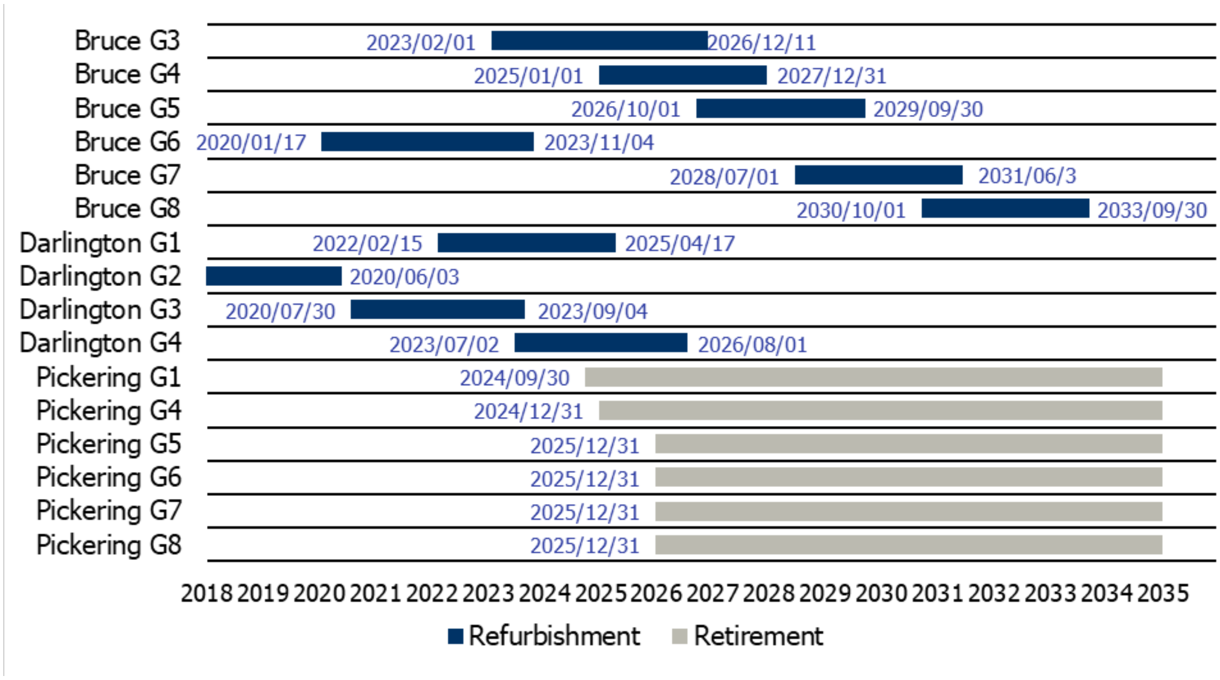
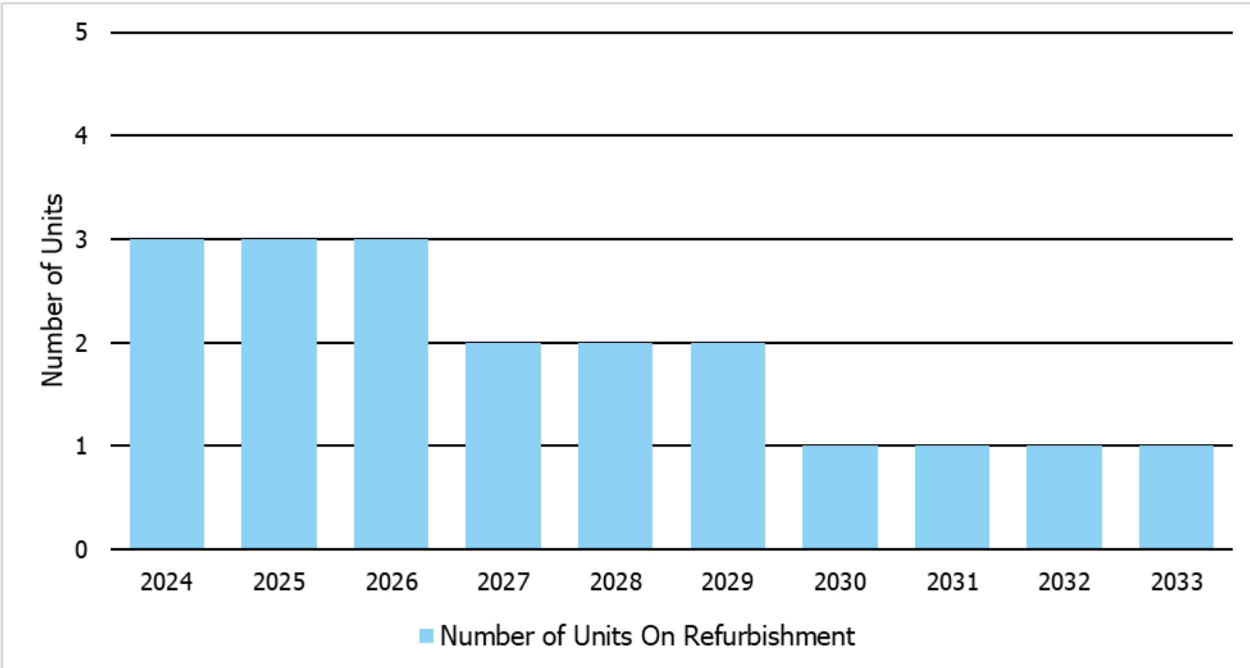



Figure 14 shows that activity will increase in the upcoming years, with between two and three units undergoing refurbishment concurrently over the summer period. Darlington and Bruce refurbishments are expected to be complete in 2026 and 2033, respectively, and by the end of 2033, a total of 8.4 GW of nuclear capacity will have undergone refurbishment.

[11] The current schedule was provided by an Ontario Power Generation and Bruce Power snapshot as of May 2022, and is subject to change.

**Figure 14 | Summer Refurbishment Outages**



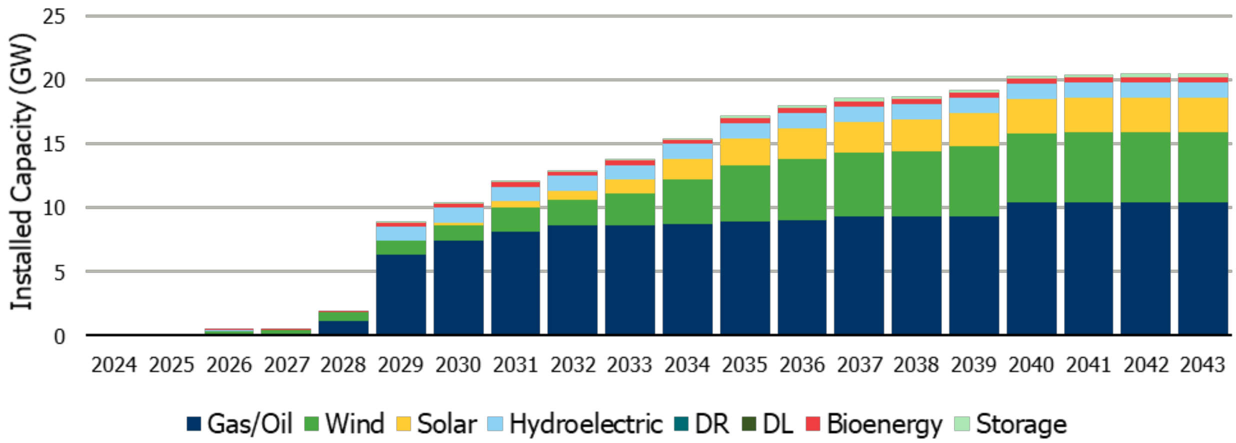

### 3.2.1.2. Contracts and Commitments Ending

Over the course of the outlook, many commitments and generation contracts held by the IESO or the Ontario Electricity Financial Corporation will expire. As shown in Figure 15, many contracts have already reached their end-of-term, and expirations of contracts increase significantly by the end of the decade.

Case 2 assumes that all resources will be reacquired once their contracts expire, recognizing that there is uncertainty as to whether these resources continue to participate in the market. The two cases have been created to explore the possible contribution of resources should they be available.

Figure 15 illustrates resources with expired contracts based on completion of contract term over the study horizon.

**Figure 15 | Existing Resources Post-Contract Expiry by Fuel Type**




## 3.3 Transmission System Outlook

This section provides a basis for understanding the role of the transmission system in transporting electricity, delivering power from producers to consumers across the province. There are constraints inherent in the existing transmission system that can limit the amount of power that can be transported, at different times and under different circumstances. This includes the ability for power to be imported and exported into and outside of the province. Over time, as transmission assets age or retire, and as new facilities come online, the transmission system capability changes. New transmission facilities that are incorporated into the assessments completed for this APO are summarized in this section.

### 3.3.1.1. The Existing Bulk Transmission System

The "bulk" transmission system refers to the network of high-voltage transmission lines that transport power over long distances. It is critical for ensuring the ability of supply resources to meet the system demand at all times – under normal conditions as well as during and after disturbances that may constrain high-voltage transfer capability across the province. Within Ontario, transmission interfaces that form the boundaries between the 10 defined IESO electrical zones are used to describe the capabilities of the bulk transmission system. The potential for power to flow across these transmission system interfaces is a key input to resource adequacy assessments, because limitations on the ability to deliver power from one part of the province to another can contribute to demand–supply imbalances at a zonal level. Over time, as the transmission system is reinforced or facilities reach their end-of-life, the nature of power flows changes and new restrictive interfaces may emerge.

Power can also be transferred between Ontario and neighbouring jurisdictions via the bulk transmission system. These transfers occur across grid "interties," which are points on Ontario's borders where transmission lines and associated facilities interconnect Ontario's grid with others. These interties provide a number of system benefits. These benefits include economic trading opportunities in the operational timeframe, the potential for contractually secured imports and exports to manage resource needs, and other benefits of participating in an interconnected system, such as supporting system stability, frequency regulation and voltage support.

Ontario's internal transmission interfaces and the locations of its interties with neighbouring jurisdictions are shown in Figure 16. More information about the transfer capabilities of Ontario's transmission interfaces and interties is provided in the [Transmission Interfaces and Interties Module].

**Figure 16 | Ontario's Major Transmission Interfaces, Zones and Interties**


### 3.3.1.2. Anticipated Changes to the Transmission System

Transmission projects that are expected to come into service within the outlook time frame are included in the base cases for the assessments completed for this APO. These projects are sufficiently far along in their planning and development to be considered committed projects for the purpose of long-term system planning.

The need for the included projects has been described in detail in past bulk system planning studies, stakeholder engagements, regional plans and regulatory approval submissions to the Ontario Energy Board.

The locations of these transmission projects are shown in Figure 17 and a summary of each is provided in Table 2.

**Figure 17 | Planned Transmission Projects**


**Table 2 | Description of Planned Transmission Projects**

| Project | Description | Expected In-Service Date |
|---|---|---|
| Ansonville to Kirkland Lake refurbishment and upgrading | The IESO recommended that Hydro One improve the capacity of these lines coincident with their planned end-of-life refurbishment | Q1 2023 |
| Etobicoke greenway project (Richview TS to Manby TS line reinforcement) | The reinforcement consists of rebuilding a currently idle 115 kV line to 230 kV, improving the bulk supply into the City of Toronto | Q1 2026 |

| Project | Description | Expected In-Service Date |
|---|---|---|
| Waasigan transmission line (phase 1) | This project will increase supply to the region west of Thunder Bay; the first phase is planned to be in-service by 2025 | Q4 2025 |
| Northeastern Ontario bulk system reinforcements | One new single-circuit 500 kV transmission line between Mississagi TS and Hanmer TS, and two new autotransformers at Mississagi TS (in-service 2029)<br>One new double-circuit transmission line between Mississagi TS and Third Line TS (in-service 2029)<br>One new single-circuit 230 kV transmission line (built to 500 kV standard) between Wawa TS and Porcupine TS (in-service 2030) | 2029-2030 |
| Eastern Ontario bulk system reinforcement | New double-circuit 230 kV transmission line from the eastern Greater Toronto Area (GTA) to Dobbin TS[12] | 2029 |

[12] The final design and routing for this option is to be determined. Multiple alternatives are being considered, including terminating the line at either Clarington TS or Cherrywood TS in the GTA.

| Project | Description | Expected In-Service Date |
|---|---|---|
| West of Chatham Area Reinforcements | Strong and sustained growth in the agricultural sector is one of the main drivers of increasing demand in Ontario, as well as growth in the automotive sectors, which has resulted in a need for additional capacity in the Windsor-Essex region<br><br>This multi-phase reinforcement project consists of:<br><br>A new Lakeshore Transformer Station (TS) at Leamington Junction (located in Lakeshore)<br><br>Two load stations in Lakeshore (South Middle Road TS DESN[13] 1 and 2)<br><br>A new double-circuit 230 kV transmission line from Chatham SS to Lakeshore SS<br><br>A new double-circuit 230 kV transmission line supplying the new DESNs from Lakeshore TS | Lakeshore TS and South Middle Road TS DESN 1 reachd in-service in 2022<br><br>Q3 2025 for South Middle Road TS DESN 2<br><br>Q4 2025 for new Chatham SS to Lakeshore SS line |
| West of London Area Reinforcements | In addition to the West of Chatham reinforcements, this project is required to supply the agricultural sector growth in the Windsor-Essex region<br><br>The reinforcement project consists of a new double-circuit 230 kV transmission line from Lambton TS to Chatham SS, and a new single-circuit 500 kV transmission line from Longwood TS to Lakeshore TS | 2028 for Lambton TS to Chatham SS lines<br><br>2030 for Longwood TS to Lakeshore TS line |

[13] DESN refers to "dual element spot network" which is a particular type of transformer station design employed to supply loads. The parallel dual supply ensures reliability can be maintained in the event of an outage or planned maintenance. A single transformer station can have multiple individual DESNs.

| Project | Description | Expected In-Service Date |
|---|---|---|
| Hawthorne-Merivale Reinforcement | The Hawthorne-Merivale transmission path supplies load in western Ottawa and delivers eastern Ontario resources and imports from Quebec to southern Ontario load centres<br><br>The reinforcement consists of upgrading the 230 kV circuits between Merivale TS and Hawthorne TS | Q4 2023 |
| Lennox Reactors | This project will address acute operational challenges resulting from high system voltages in eastern Ontario and the GTA during low-demand periods, and consists of two 500 kV line-connected shunt reactors to be installed at Lennox TS (near Napanee) | Q2 2023 |
| East-West Tie Reinforcement | The line project reached an in-service milestone in 2022 | In-service |
| FETT Capacity Upgrade (Richview-Trafalgar Reinforcement) | The Richview-Trafalgar reinforcement will increase the FETT transfer capability by approximately 2,000 MW through upgrades to sections of the existing 230 kV lines between Trafalgar TS and Richview TS, and it will enable some of the capacity required east of the FETT interface to be replaced with capacity sited elsewhere in the province | Q4 2026 |

# 4 Resource Adequacy

Capacity needs continue to emerge after Pickering NGS is retired. Although forecasted demand is increasing, the needs in the short and medium terms are partially offset by actions taken in response to previous outlooks by stakeholders, the government and the IESO. The result is improved adequacy compared with the previous year's outlook. Consistent with previous outlooks, energy requirements for new resources continue to emerge around 2029. If they remain available post-contract expiry, existing resources will need to operate much differently than today, to meet increased energy demands.

A key aspect of power system reliability is resource adequacy, which describes the balance of supply and demand on the system. The IESO calculates capacity requirements by performing a probabilistic resource adequacy assessment, which compares the demand forecast with anticipated resource performance to simulate the range of possible future system conditions. Loss of load expectation (LOLE), a measurement of resource adequacy, is defined as the average number of days per year during which supply is expected to be insufficient to meet demand. Reliability criteria[14] require that the IESO maintain enough capacity such that the LOLE is no greater than 0.1 days/year.

Probabilistic assessments are standard practice across North America and are part of the IESO's regulatory requirements. Over time, as forecasted demand changes, resources enter and exit the market and the composition of the supply outlook changes, the IESO's capacity requirements will change.

The IESO also considers a number of risks in resource adequacy assessments. For example, actual demand may be higher or lower than forecast depending on weather conditions. Resources may be unavailable in real time due to planned maintenance or equipment failures. Variable generators – such as wind and solar – may provide relatively low levels of effective capacity, since their production is dependent on environmental conditions. Finally, major projects, such as ongoing nuclear refurbishments, may face return-to-service delays and experience a higher outage rate after they return.[15]

[14] See the NPCC's Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System, Section R4, page 6; and the IESO's Ontario Resource and Transmission Assessment Criteria, Section 8.

[15] See the 2022 APO Resource Adequacy and Energy Assessment Methodology for additional information.

## 4.1 Reserve Margin

The IESO annually publishes a five-year forecast of reserve margin requirements at the time of projected annual peak. The reserve margin requirement is the amount of resources Ontario needs to have available over and above peak demand under normal weather conditions (represented as a percentage of peak demand).

There are various reasons for year-to-year variations in the reserve margin requirement. In addition to the allowances for uncertainties identified by the Northeast Power Coordinating Council (NPCC), the IESO includes additional reserve to account for risks associated with nuclear refurbishments, with the amount varying, depending on the refurbishment schedule. A year with higher-than-average planned outages will also have a higher reserve margin requirement.

In Ontario, summer capacity needs are generally much higher than winter capacity needs. The main driver of this difference is demand – summer peaks, driven by air conditioning demand, tend to be higher and more variable than winter peaks. Existing resources, particularly gas, hydroelectric and wind, also provide less effective capacity in the summer than in the winter. While the demand forecast is expected to switch from summer to winter peak in the mid-2030s, the system requirements continue to be greater in the summer than in the winter.

To address the needs identified in Table 3, Ontario's Ministry of Energy directed the IESO to procure 4,000 MW of new capacity through three separate procurements. It also announced its support of a plan to extend operations at Pickering Nuclear Generating Station through to September 2026. In addition, the IESO announced new energy efficiency programs targeting needs in 2025-2027.

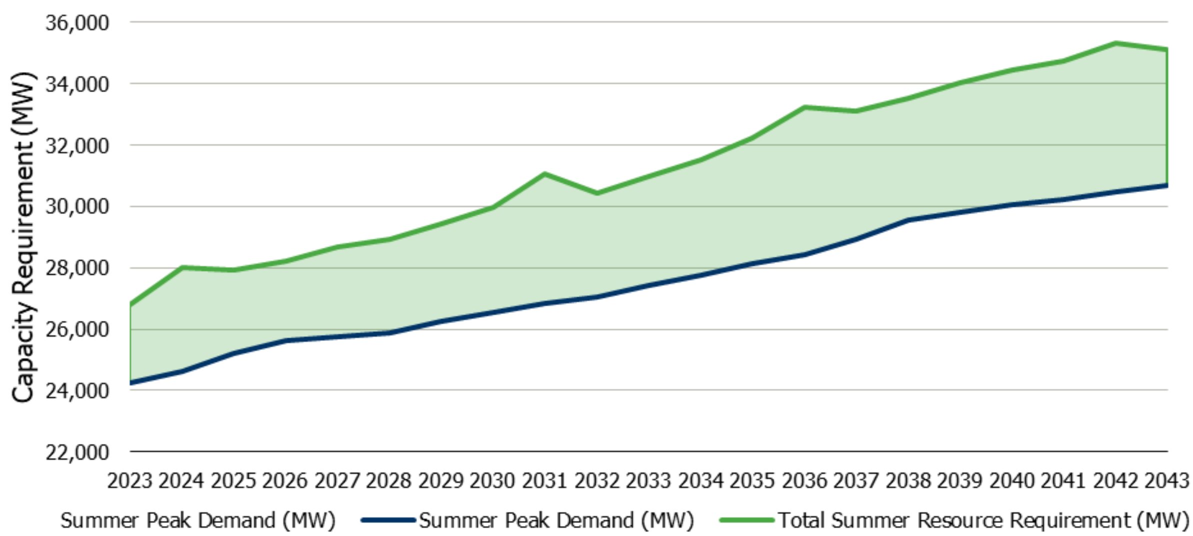
The methodology used to calculate effective capacity for each resource type also affects the reserve margin.

The reserve margin requirements for the next five years are shown in Table 3, and for the full horizon in Figure 18. Case 2 was used for the calculation of reserve margins – i.e., the continued availability of existing resources is assumed. The APO Resource Adequacy and Energy Assessments Methodology describes how the reserve margin is calculated.

**Table 3 | Five-Year Reserve Margin, with Continued Availability of Existing Resources**

| Five-Year Reserve Margin | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Summer peak demand (MW) | 24,260 | 24,632 | 25,211 | 25,636 | 25,738 |
| Existing summer effective capacity (MW) | 26,789 | 28,649 | 28,211 | 26,983 | 27,270 |
| Total resource requirement (MW) | 26,794 | 28,025 | 27,907 | 28,206 | 28,660 |
| Reserve margin available (MW) | 2,529 | 4,017 | 3,000 | 1,347 | 1,532 |
| Capacity surplus/deficit (MW) | -5 | 624 | 304 | -1,223 | -1,390 |
| Reserve margin available (%) | 10% | 16% | 12% | 5% | 6% |
| Reserve margin requirement (%) | 10% | 14% | 11% | 10% | 11% |

**Figure 18 | Reserve Margin Requirement, 2023-2043**




## 4.2 Provincial Capacity Adequacy Outlook

Capacity adequacy can be represented in terms of surplus or deficit, relative to a set of demand and resource assumptions. Resource adequacy is assessed for the summer and winter seasons using the demand forecast outlined in Section 2, and the supply and transmission outlook in Section 3.

In this section, the capacity deficit represents the total amount of capacity, on an effective capacity basis, that the IESO must acquire to satisfy LOLE requirements. The capacity deficits for summer and winter periods for supply Cases 1 and 2 are shown in Figure 19 and Figure 20. Summer capacity needs emerge in 2026 with long-term needs being driven by nuclear retirement and refurbishment, resources reaching the end of their contracts, and increased in demand. Even with the system forecasting a transition to a winter peak in 2036, system needs are generally greater in summer than in winter due to seasonal differences in resource performance.

**Figure 19 | Summer Capacity Surplus/Deficit**

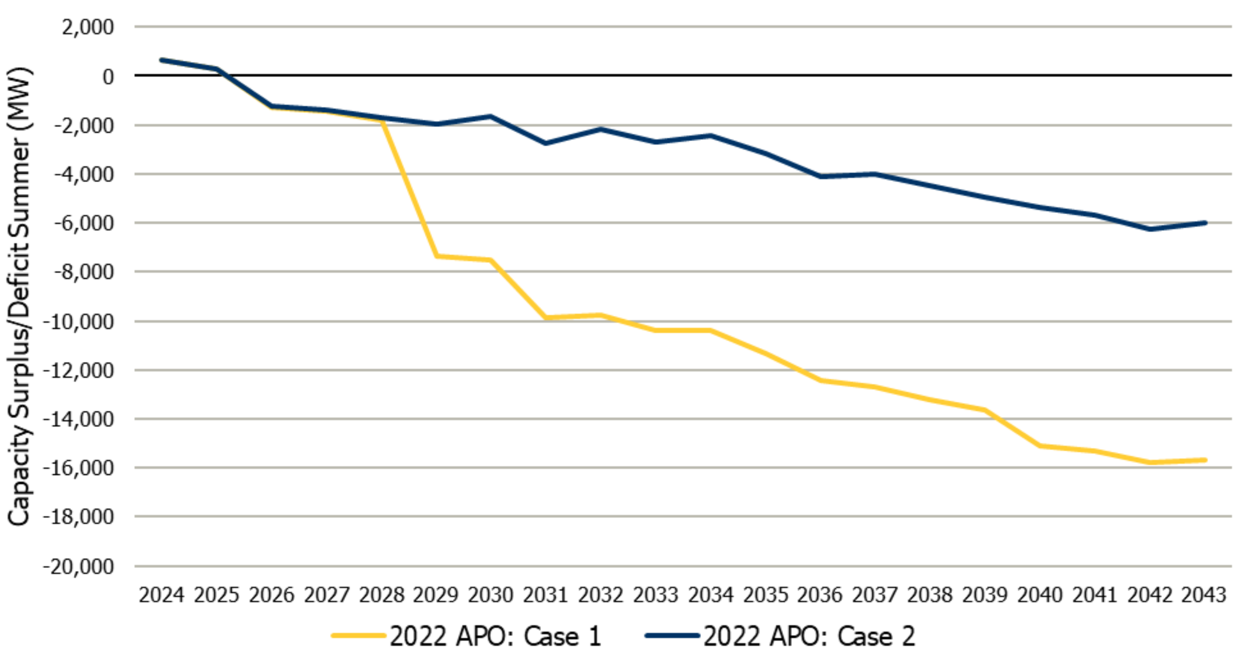
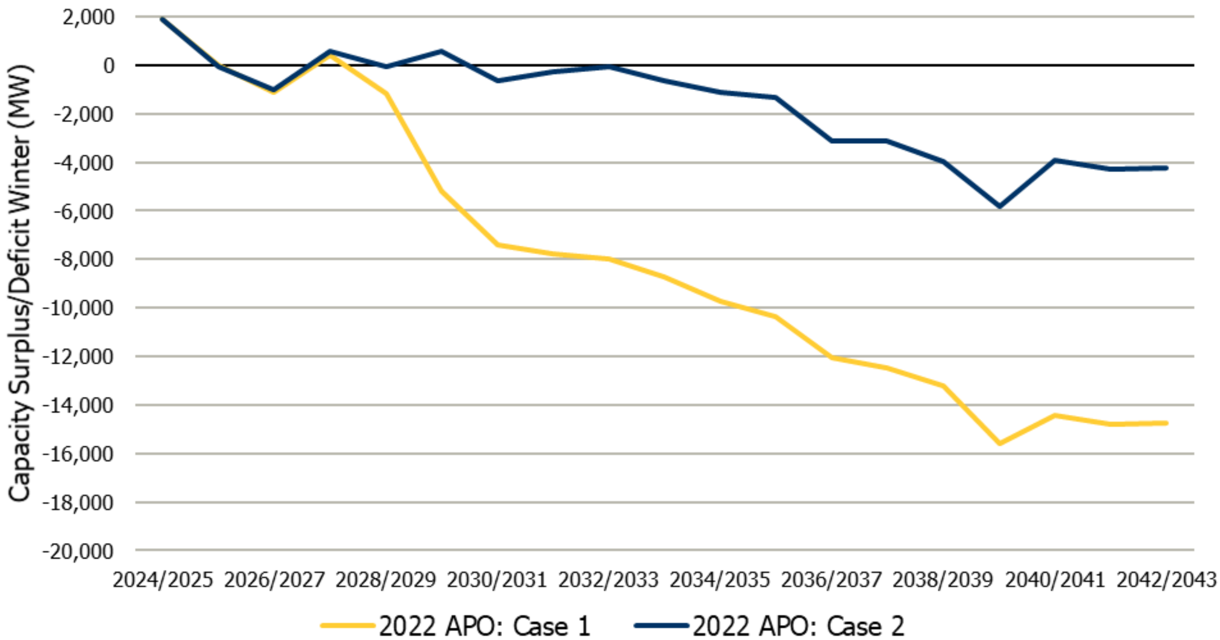


**Figure 20 | Winter Capacity Surplus/Deficit**




## 4.3 Provincial Energy Adequacy Outlook

In addition to capacity adequacy, the provincial energy adequacy outlook helps determine Ontario's ability to meet electricity needs and to characterize the nature of those needs. The energy adequacy assessment does not include any economic imports or exports across Ontario's interconnections in order to evaluate the system assuming self sufficiency.

The extent to which an energy adequacy need emerges will depend on the availability of existing resources post-contract expiry and their ability to produce energy or reduce demand. The energy adequacy outlook for Case 1 is shown in Figure 21. Figure 22 shows the energy adequacy outlook for Case 2[16].

[16] Assumes that Lennox GS will be available for capacity when needed, and not providing sustained volumes of energy after its current contract. This assumption was made given the facility's age and uncertainty around its availability for the duration of the study period.

**Figure 21 | Energy Adequacy Outlook (Case 1)**

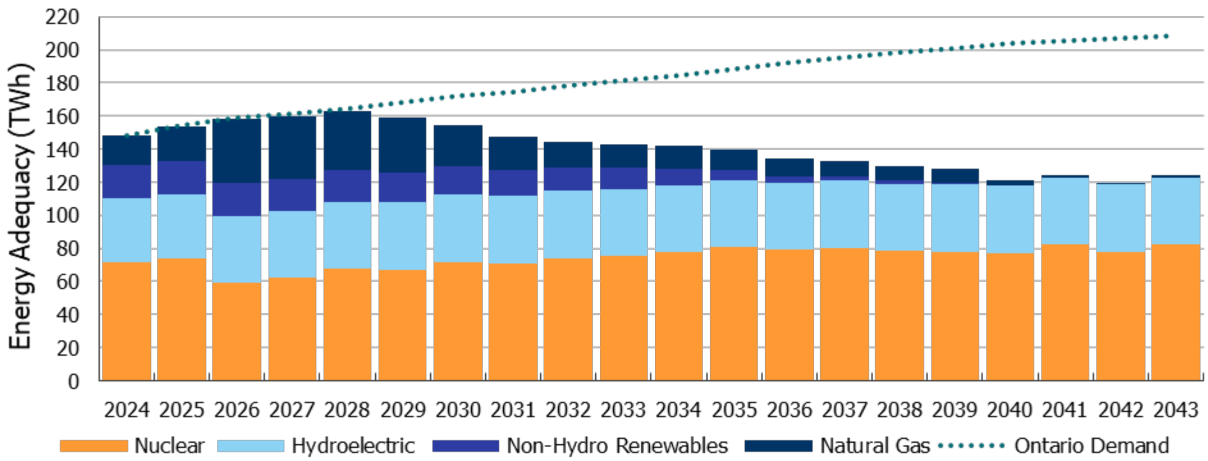
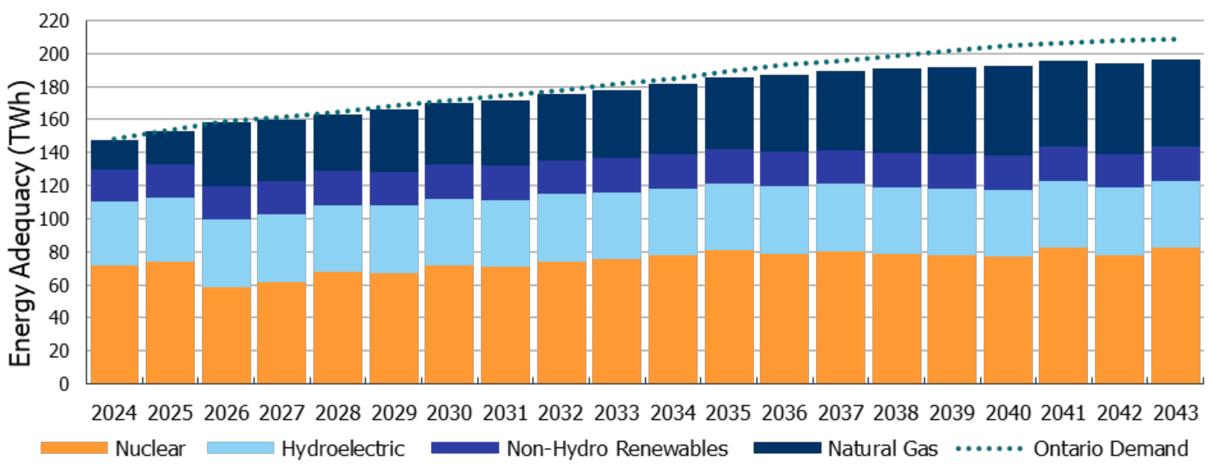



**Figure 22 | Energy Adequacy Outlook (Case 2)**




Utilizing the existing and committed fleet, absent the availability of existing resources post contract expiry in Case 1, an energy shortfall is observed in the late 2020s. Some of this can be met should existing resources remain available post contract expiry. In Case 2, existing resources, should they continue to be available post contract expiry, can meet energy demands in most circumstances until the mid-2030s. An energy shortfall begins to emerge near the end of the planning horizon, driven largely by increases in demand, indicating a need for new incremental resources. The inclusion of interactions of imports and exports with IESO's neighbouring system will change the dynamics of the generation output.

Surplus baseload generation (SBG) occurs when output from baseload resources exceeds demand and is normal in electricity markets with high portions of non-dispatchable (i.e., baseload and intermittent) resources (e.g. nuclear, must-run hydroelectric, wind and solar). Periods of SBG require the IESO to use market mechanisms, such as exports, variable generation curtailment and nuclear manoeuvers/curtailment, to correct the imbalance. As demand increases, SBG becomes close to zero under both Case 1 and Case 2 as nuclear units undergo refurbishment and retirement.

## 4.4 Uncertainties

The outlook on capacity and energy adequacy can be higher or lower and influenced by a number of factors. A number of risks and uncertainties that would influence the adequacy assessments are outlined below (in no particular order).

- **Market exit:** With an aging fleet, the frequency and duration of forced outages increases; this reduces supply, and could trigger market exit of resources.
- **In-service delays for new generation**: Delays in project development, approvals, construction, commissioning, etc., can reduce expected supply.
- **Poorer-than-expected performance:** Poor performance over the life of the asset can result from its age, higher-than-expected forced outages, poorer-than-expected operations of the assets and other factors.
- **Management of planned outages:** With the addition of new generation and transmission in the future, managing and coordinating outages will become increasingly challenging and create uncertainty around availability.
- **Nuclear refurbishments and retirements**: Nuclear refurbishment and retirement schedule dates are subject to change and, in the case of retirements, subject to regulatory approval – which impact the capacity and energy adequacy outlook.
- **Supply chain:** Batteries are facing macroeconomic challenges, along with supply chain issues and significant competition for materials due to buying by auto manufacturers. Grid-scale batteries have been challenged to stay on budget and schedule.
- **Fuel availability:** The risks of fuel unavailability will influence adequacy assessments.
- **Policy uncertainties**: Emitting resources face significant uncertainty related to climate change and government regulation, including but not limited to Canada's Clean Electricity Regulations, which are currently under development.
- **Extreme events**: The frequency, duration and intensity of extreme events such as droughts, temperatures changes, etc., could impact ratings, fuel availability and outages of assets.

# 5 Transmission System Reliability

With capacity needs forecast to arise in the planning horizon, a robust transmission system will play an increasingly important role in ensuring that resources can supply demand both provincially and to customers locally. This APO identifies transmission system issues that will limit the ability to reliably supply forecasted demand over the next 20 years, and triages these issues, identifying those that require further IESO bulk system planning and those that can be addressed by acquiring capacity in specific areas.

The transmission system is critical for ensuring the ability of supply resources to meet system demand at all times, as supply resources are often distant from customers. As part of this APO, the IESO undertook an assessment of the bulk transmission system to identify potential transmission issues arising over the 20-year outlook.

Other sources of information, including insights from community and customer engagement, IESO regional planning, recent bulk system studies, the age of existing transmission system assets[17] and IESO operational experience, were also brought together to inform transmission issues that may require further bulk system planning to address, or that may result in local capacity needs. All of the issues identified were reviewed as part of a triaging exercise, reported in Section 7.2. The triaging determined the issues that the IESO plans to address by acquiring capacity within specific areas, versus those that will be addressed through further IESO bulk system planning that examines transmission upgrades as a possible solution.[18]

## 5.1 Bulk Transmission System Constraints

After many years of strong supply, Ontario is entering a period of emerging electricity system needs. As reported in section 4, provincial energy and capacity needs will continue to grow over the next two decades as the province sees significant demand growth in response to increasing electrification of transportation and industrial processes, as well as ongoing economic development. A robust and reliable transmission system will play an increasingly important role in meeting these coming needs. The transmission issues summarized in this section reflect constraints on the transmission system's ability to supply forecast residential, commercial and industrial demand growth in all areas of the province, and consider decisions around the end-of-life of existing transmission facilities, to ensure the bulk system can adapt to meet future needs.

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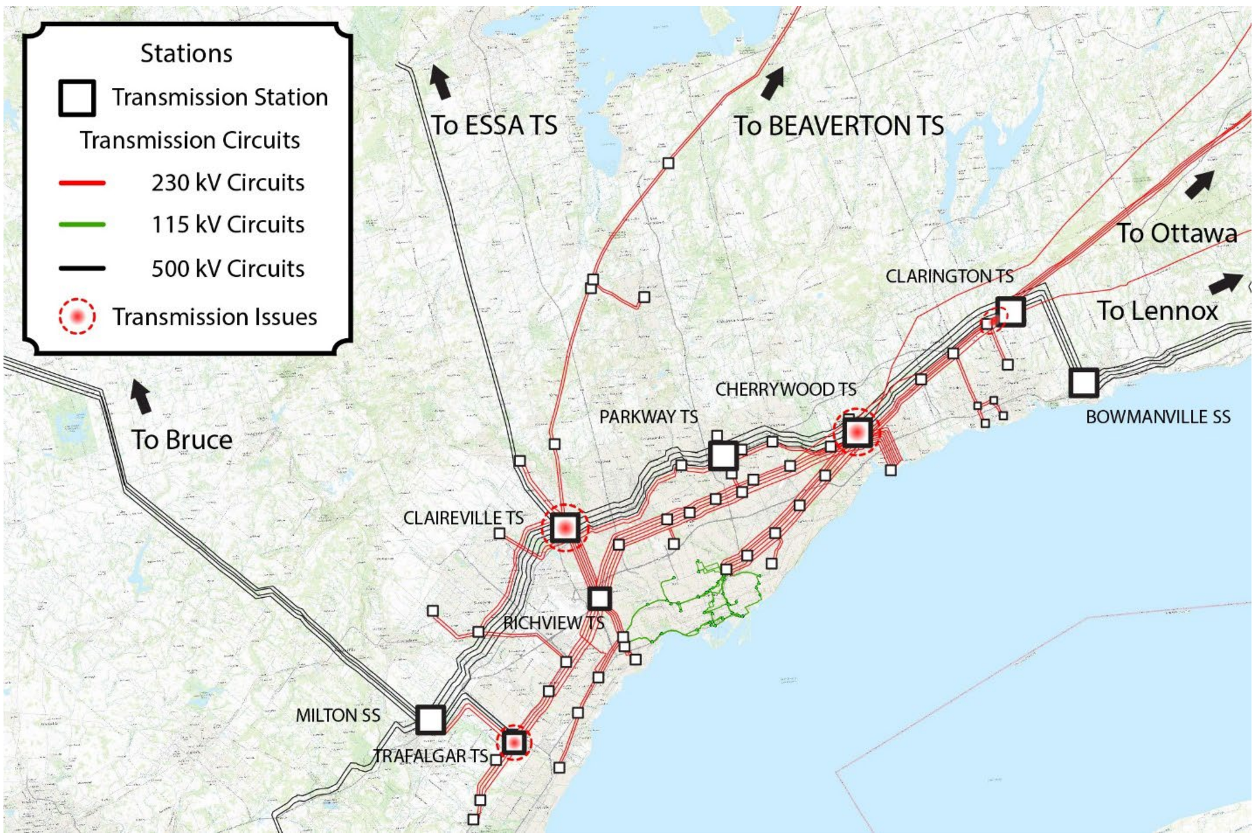
[17] Data on the age of transmission system assets were provided by Hydro One Networks Inc.

[18] Future IESO bulk planning studies are listed in a Schedule of Planning Activities (Section 7.2.3), while local capacity requirements will go on to inform the IESO's *Annual Acquisition Report*.

### 5.1.1.1. Transmission Supply to the Greater Toronto Area (GTA)

Issues affecting the bulk transmission system supplying the GTA are forecasted to emerge as a result of electricity demand growth in the GTA, which is forecasted to increase by more than 25 per cent over the next 20 years. There are few generation resources located in the GTA, and particularly in the City of Toronto, so the area is heavily reliant on the bulk transmission system, including a number of major autotransformer stations that step power down from the 500 kV network to the 230 kV network that supplies customers throughout the area. The transmission facilities supplying the GTA are shown in Figure 23.

**Figure 23 | Bulk Transmission Supply to the Greater Toronto Area**




By the end of the plan period (i.e., by 2042), several autotransformers at three major stations in the GTA will reach their thermal limitations. These thermal overloads are forecasted to begin as early as 2027, beginning with one of the autotransformers at Claireville TS. By about 2032, additional autotransformers at the Claireville TS, Cherrywood TS and Trafalgar TS are forecast to reach their thermal limits.

Expansions at Kleinburg TS is one possible solution. Kleinburg TS, which is located north of Claireville TS, has the potential to be expanded with new autotransformers to improve local supply capacity in a rapidly growing area of the GTA. There may also be the potential to increase capacity at other transformer stations in the GTA.

### 5.1.1.2. East GTA: Supply between Clarington TS and Cherrywood TS

Following the retirement of Pickering NGS and with continued demand growth in Toronto and the GTA, two of the 230 kV transmission circuits between Clarington TS and Cherrywood TS, T23C and T28C, are expected to reach their thermal limits after 2032.[19] The limiting section of these circuits is between Clarington TS and Wilson Junction, which supplies demand in Oshawa and growing areas of the eastern GTA. The IESO is aware that another 230 kV circuit along the same corridor (T28C) is very old (originally built in 1931). Retiring this parallel circuit would result in additional electricity flows on T23C and T29C, therefore options to address its end-of-life should be taken into account in evaluating a solution to this issue.

### 5.1.1.3. Essa Area Transmission System

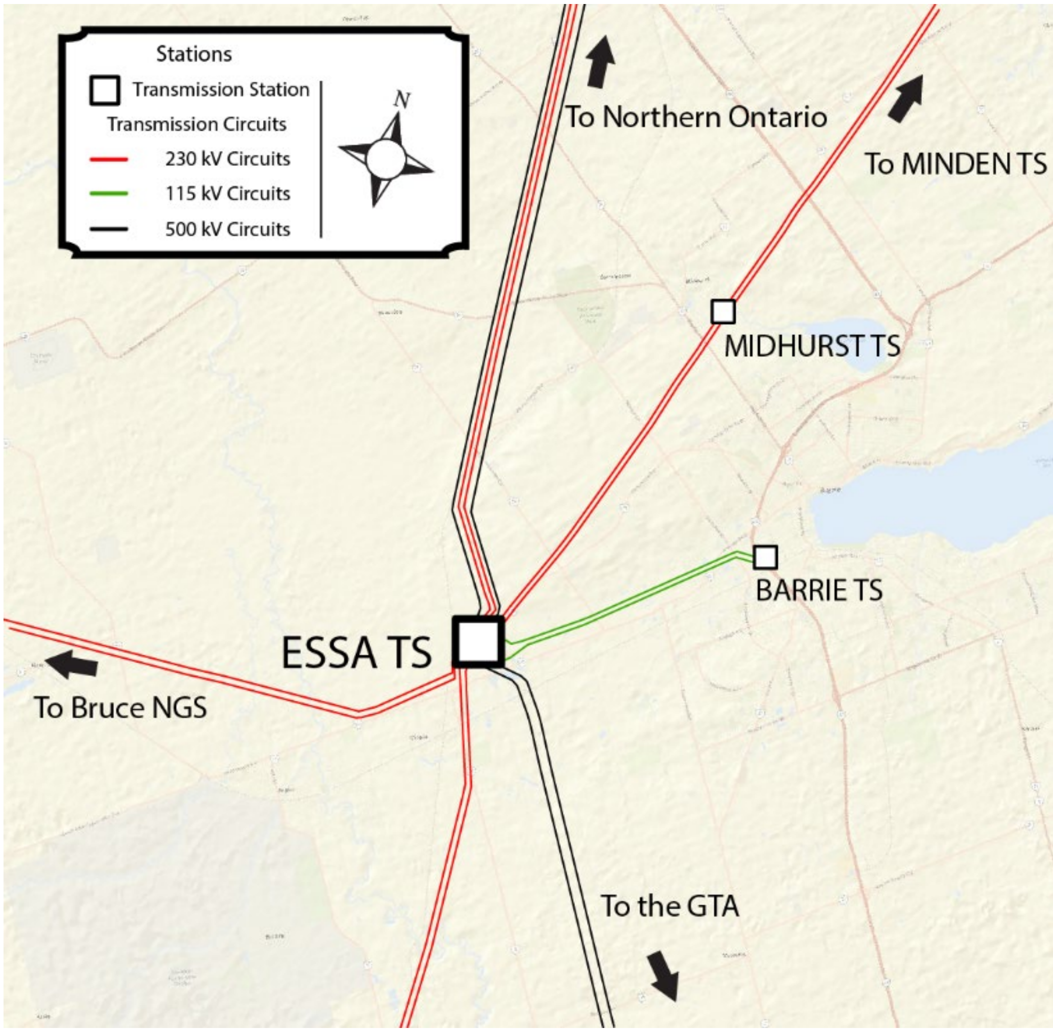
Essa TS, located near the City of Barrie, is a major point of intersection for the bulk transmission system, linking northern and southern Ontario as well as facilitating power delivery from Bruce NGS. The 230 kV transmission lines connecting Essa TS to Minden TS are expected to reach their thermal capacity beginning in 2032 or shortly thereafter, with the issue progressively worsening up to the end of the plan period in 2042. This is primarily due to forecasted increasing local area demand.

Issues affecting the 500/230 kV autotransformers at Essa TS were also found in the Barrie-Innisfil Integrated Regional Resource Plan (IRRP) published in May 2022. There is a risk that the loss of one autotransformer at Essa TS will overload its companion transformer. The Barrie-Innisfil IRRP recommended that this issue be addressed through bulk system planning.

Essa TS and the nearby transmission facilities are shown in Figure 24.

[19] The assessment indicates 89% loading by 2032, increasing to 112% by 2042.

**Figure 24 | Bulk Transmission Supply in the Essa TS Area**



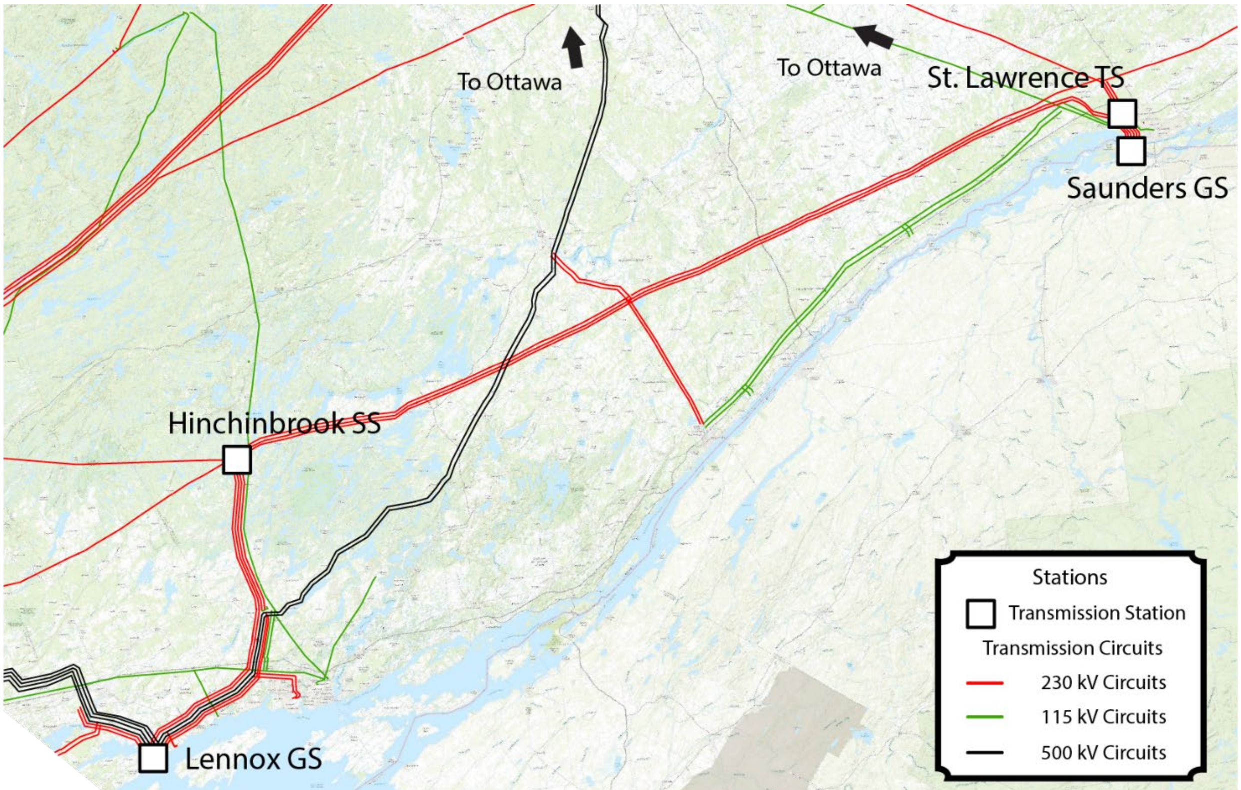

### 5.1.1.4. Transmission Issues in the Lennox–St. Lawrence Area

The 230 kV transmission lines between Lennox GS and St. Lawrence TS near Cornwall (via Hinchinbrooke Switching Station) were originally built in 1941 and are approaching the end of their useful service life. The eventual end-of-life of these transmission lines and the possible impacts on the bulk power system need to be evaluated as a part of the IESO's accountability for independent power system planning. The scope of a bulk study will also need to consider the recommendations from the recent Peterborough-to-Kingston IRRP,[20] decisions around Lennox GS and opportunities to address existing operability issues affecting Saunders GS, which also connects to St. Lawrence TS.

[20] This includes ensuring the bulk system has the capability to supply long-term demand growth in Belleville which is supplied from a transmission line emanating from Lennox TS.

The transmission facilities in the Lennox-St. Lawrence area are shown in Figure 25.

**Figure 25| Bulk Transmission Supply in the Lennox–St. Lawrence Area**




### 5.1.1.5. Transmission Issues in Central-West Ontario (East of London)

Potential economic development opportunities in southwestern Ontario could stress the bulk transmission system between Buchanan TS (near London) and Middleport TS (near Hamilton-Brantford). The IESO is aware of several potential new customers interested in connecting to the grid in this area, and is following the status of these new connections closely. Information from regional planning activities, and the potential for changes in the predominant bulk power flows through the area as the provincial resource mix evolves will be considered in evaluating the need and timing of bulk system planning in this part of Ontario.

### 5.1.1.6. System Issues in Northern Ontario

Significant transmission reinforcements that are currently planned or being implemented in northwestern and northeastern Ontario will alter the voltage profile in the north. There are already significant challenges with voltage control in northern Ontario today, and the IESO's system operations rely heavily on local generators to provide reactive support services. As a follow up to the Northeast Bulk System Plan,[21] a study is underway to address these reactive compensation needs. The scope of this study will include all 230 kV and 500 kV equipment in Northern Ontario. Planning scenarios will include both system peak and minimum loading conditions as well as long-term conditions after future planned transmission reinforcements are in-service. As details about this study emerge, they will be communicated to stakeholders.

Future changes to the provincial supply mix, including potential for expansion of hydroelectric generation in the north, will also require assessment of potential impacts to the bulk transmission system and the capability of the grid to deliver these resources to load centres.

### 5.1.1.7. Interties with Neighbouring Jurisdictions

Ontario's interties are critical for enabling import and export activity, as well as enhancing system stability through participation in the Eastern interconnection. The IESO recently conducted a screening study of Ontario's interties, including those with Manitoba, Minnesota, New York and Michigan. The study focused on identifying interties where a long-duration outage, caused by the unexpected failure of a unique piece of equipment such as a phase shifter,[22] could result in reliability impacts for Ontario electricity customers. Consistent with established North American reliability standards,[23] the screening study considered factors such as utilization of the tie, the age and condition of equipment, the impact of outages on intertie limits or operation and any known operability concerns. The study found that major equipment at the Ontario—Manitoba intertie is approaching its end-of-life, including two phase shifters and two step-up transformers. The Manitoba–Ontario interconnection has been in-service since 1972.

The IESO will initiate a joint study with Manitoba Hydro and Minnesota Power in 2023 to plan for the end of life of this critical equipment.

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[21] For more information, please visit the IEO website: [https://www.ieso.ca/en/Get-Involved/Regional-Planning/Northeast-Ontario/Bulk-Planning](https://www.ieso.ca/en/Get-Involved/Regional-Planning/Northeast-Ontario/Bulk-Planning)

[22] Also known as a Phase Angle Regulator. These are specialized pieces of equipment that help control the power flow between two interconnected transmission systems.

[23] NERC TPL-001, R2.1.5

# 6 Operability

A reliable system is one that is both resource adequate and operable. In addition to requiring that energy and capacity needs are met, Ontario's supply mix must contain a sufficient amount of attributes to support reliable grid operations and respond to the inherent variability and uncertainty of electricity supply and demand. The IESO conducts operability assessments to assess the sufficiency of the supply mix to provide the necessary attributes, and as the supply mix evolves, these assessments will become more critical to ensuring reliable operations in the future.

## 6.1 Background

#### 6.1.1.1. Defining Operability

Operability refers to the IESO's ability to manage a variety of conditions on the power system as they occur in real time. The IESO works to ensure that the power system is reliable under changing system conditions, variability of supply and fluctuation in load, while respecting thermal, voltage and transient stability limits on the system. Operability is assessed in advance to ensure that the power system is adequately prepared for expected real-time conditions, while also having the ability to absorb and adapt to unexpected changes.

#### 6.1.1.2. Assessing Operability

The IESO routinely conducts operability assessments to assess the sufficiency of various attributes that enhance power system operations. Some of these attributes include flexibility, ramping and ancillary service needs, which are described below. The 2021 APO Ancillary Services Module included the outcomes of the IESO's regulation service and black start needs assessments, both of which will continue to be included in this and future APOs. Moving forward, operability will continue to be discussed in the APO, and this discussion is expected to expand to cover additional attributes and assessments as the set of resources that make up Ontario's power system evolves.

#### 6.1.1.3. Operability Services

Operability is achieved by having a diverse set of resources with a balance of characteristics that allow the power system to respond to changing conditions. Diversity of the resource mix ensures that the risks specific to each technology and fuel type are mitigated, and helps the power system withstand a wide variety of conditions, including short-term extreme weather, mid-term environmental extremes and fuel delivery challenges.

A diverse resource mix includes resources that can provide services that include, but are not limited to, flexibility, ramping capability and ancillary service capability:

- **Flexibility** is the ability of the system to respond to intra-hour circumstances or conditions that arise in real time, depending on the supply and demand balance that materializes. As Ontario's electricity system decarbonizes, an increased penetration of variable generation and storage resources is anticipated to make up the resource mix. As these resources have inherent uncertainties (e.g., fuel supply, output) that can directly affect the need for flexibility, assessments of this attribute of operability will be necessary to ensure that a sufficient amount of highly flexible resources are available to respond to system needs.
- **Ramping capability** is the ability of the system to follow changes in Ontario demand from hour to hour and during periods of large demand changes. As sectors of the economy decarbonize, the shape of the electricity demand curve is anticipated to change as the reliance on Ontario's electricity system grows to meet broader emissions targets. This is anticipated to create an additional need for system ramping capability as periods of load pick-up increase during the day, requiring assessments of this attribute of operability to ensure that the power system has a sufficient amount of resources that can adjust output to meet needs.
- **Ancillary service capability** is required to maintain the reliability of the power system, and includes regulation service, black start capability, operating reserve and reactive support and voltage control. These services ensure that supply and demand on the power system are matched, that the system can be restored in a timely manner following a blackout, that the system can meet energy needs during unanticipated events in real-time and that acceptable voltage levels are maintained to move power through the transmission and distribution system from generators to end consumers. The IESO performs assessments of regulation service and black start needs (provided below) looking out five years, as ancillary service needs are highly dependent on localized assessments that factor in the location of new and retiring facilities. As the power system transitions, further assessments of ancillary service needs are anticipated.

## 6.2 Ancillary Services Needs Assessments

The IESO conducts a regulation needs assessment to determine if an incremental regulation need exists in future years, and a black start capability assessment to determine if the present portfolio is sufficient to satisfy needs. Regulation service and black start capability are described in more detail here, and the results of the assessments are described below.

#### 6.2.1.1. Methodology and Results of Regulation Needs Assessment

This year's regulation needs assessment covered a period extending to 2028. The objective of the assessment was to assess the amount of regulation service required to maintain compliance with the North American Electric Reliability Corporation's Reliability Standard BAL-001-2 over the assessed period. The assessment considered the effects of demand and variable generation forecast error as well as the impact of resources generating outside of their dispatch targets.

The 2022 regulation needs assessment updates the assessment identified in the March 2022 Reliability Outlook, based on incremental improvements.

The assessment found that there may be an increased need for regulation service in the upcoming years. The IESO is currently considering options to address the potential need for more regulation.

#### 6.2.1.2. Black Start Capability

Consistent with the findings in the 2021 APO, the IESO's latest black start capability assessment confirmed that the present portfolio satisfies the current black start needs as defined in the Ontario Power System Restoration Plan.

# 7 Integrating Electricity Needs

The characteristics of system requirements change over the course of the horizon. The requirements are further explored to understand the magnitude, volume, timing, location, frequency and intensity of system needs. In general, the outlook evolves from a system requiring peaking capacity to a system requiring energy producing resources, which is influenced by increases in demand, and evolution of the supply and transmission outlook.

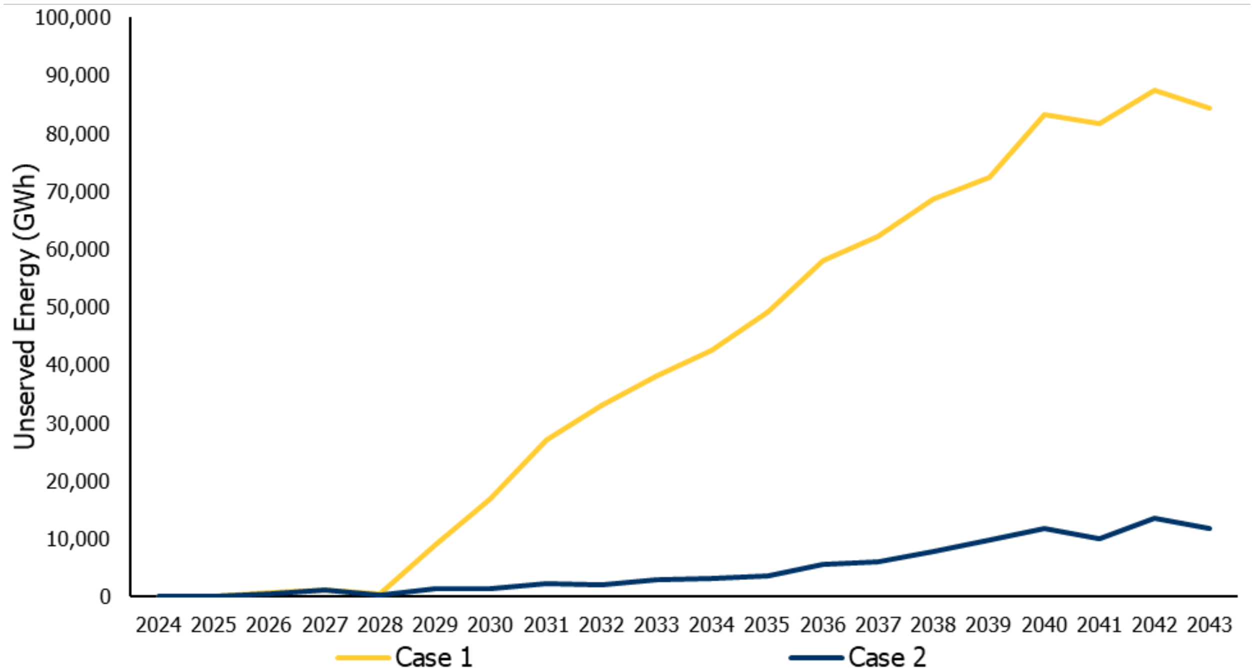
This section integrates the findings and outcomes of the previous chapters. It examines system needs in a number of ways to help illustrate system requirements from different perspectives – and ways to meet these system requirements – to inform future AARs, transmission plans and other studies.

## 7.1 Description of Resource Adequacy Needs

Further to capacity requirements, Figure 26 illustrates the potential for unserved energy, demonstrating that capacity needs identified also eventually lead to an energy need. Unserved energy occurs when requirements remain even after all generators have been fully dispatched (global unserved energy), or transfer limits have been reached (local unserved energy).

In Case 1, the potential for unserved energy begins to grow substantially in 2029. By the end of the planning horizon, it reaches about 84 TWh. These considerable energy shortfalls are mainly due to the input assumptions of Case 1, assuming facilities are not available after contract expiry, with many natural gas and renewable contracts reaching end-of-contract term around this time. In Case 2, unserved energy in Ontario is expected to increase throughout the planning horizon. By the end of the planning horizon, it reaches about 12 TWh, assuming contract extensions or continued market participation for both dispatchable resources and renewables. This suggests that existing domestic resources alone will not be sufficient to meet energy requirements and that Ontario will require new resources and/or imports.

**Figure 26 | Potentially Unserved Energy**




The following duration curves illustrate the relationship between capacity requirements and capacity utilization. Figure 27 shows the duration curves of unserved energy in Case 1 for the start and end year of the study period. By 2043, there is a need for about 6,000 MW of baseload-type resources to meet unserved energy and additional peaking/intermittent requirements of about 10,000 MW.

**Figure 27 | Unserved Energy Duration Curves, Case 1**

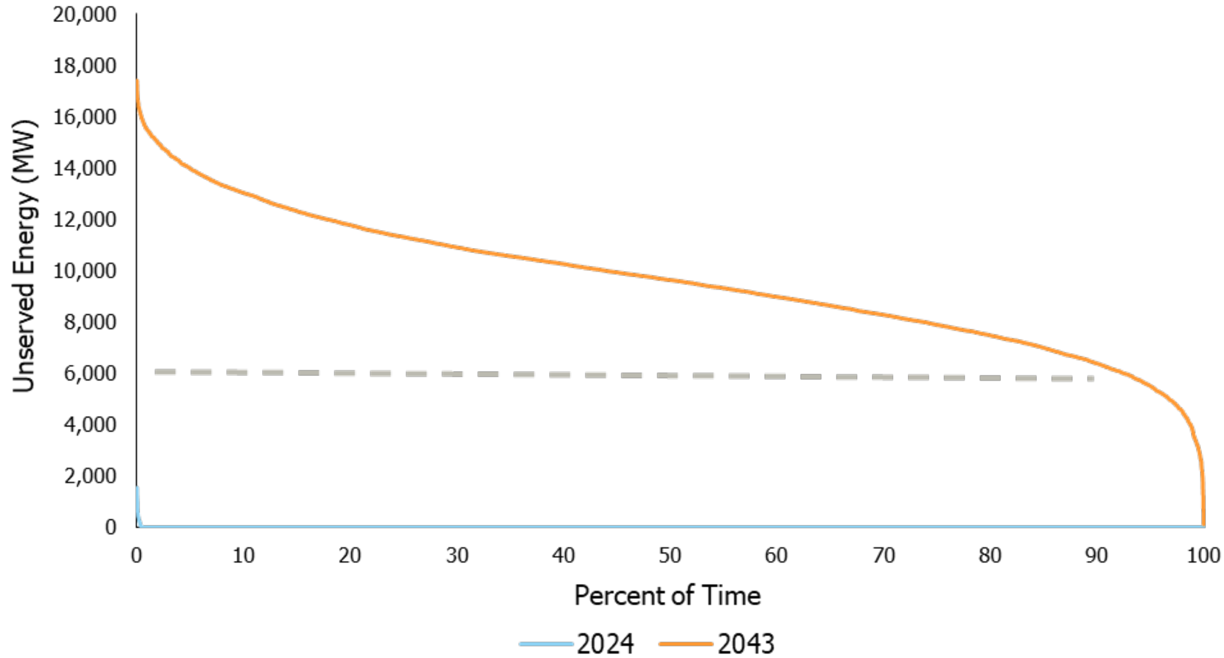



Figure 28 shows the duration curves of unserved energy in Case 2 for the start and end year of the study period. By 2043, unserved energy occurs at most hours with continued availability of existing resources. The need for baseload resources is not significant; however, it could increase should existing resources exit the market. The peaking portion of the duration curve could be met with options such as demand-side management or firm imports.

**Figure 28 | Unserved Energy Duration Curves, Case 2**

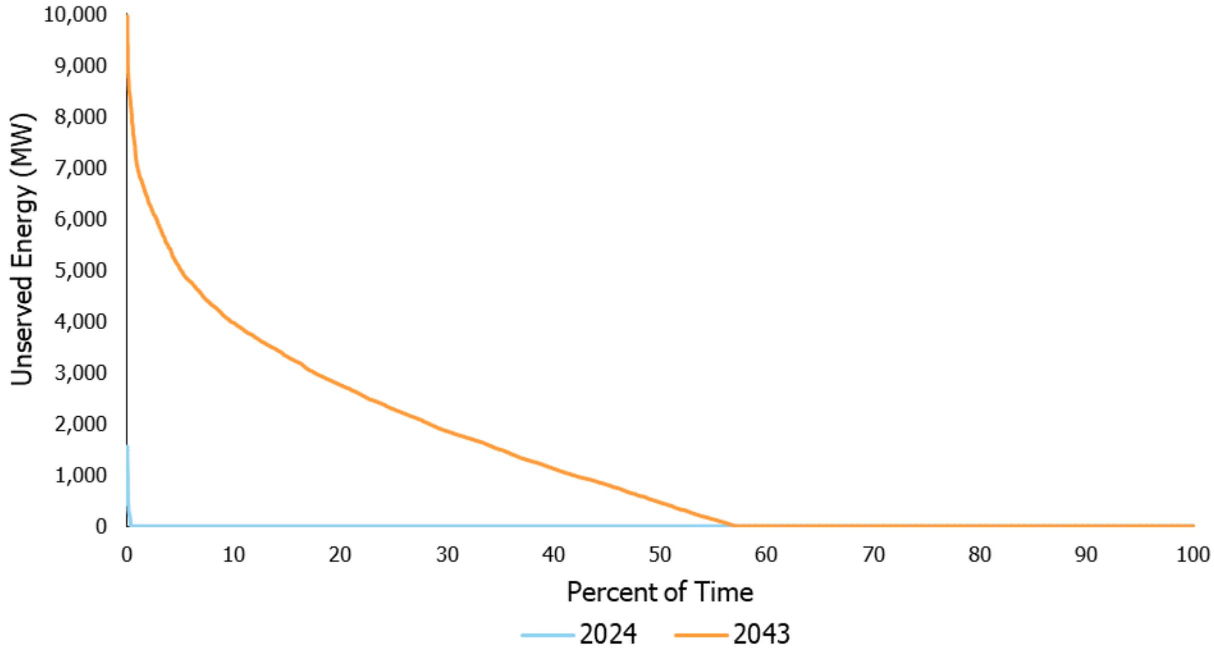



Figure 29 and Figure 30 illustrate the duration curves of the unserved energy in year 2043, by taking the annual values as shown in Figure 27 and 28 and separating them by summer and winter. These figures demonstrate that total unserved energy (area under the curve) is greater in the winter, although peak unserved energy may occur in the summer.

**Figure 29 | Unserved Energy By Season, Case 1**

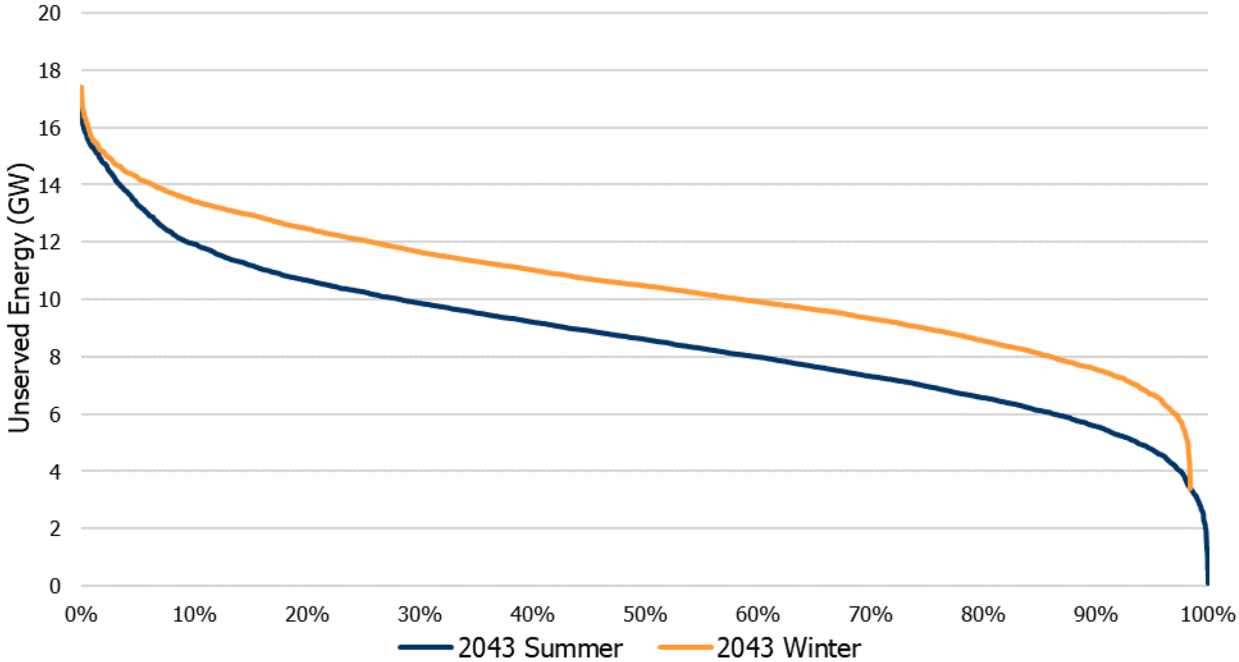
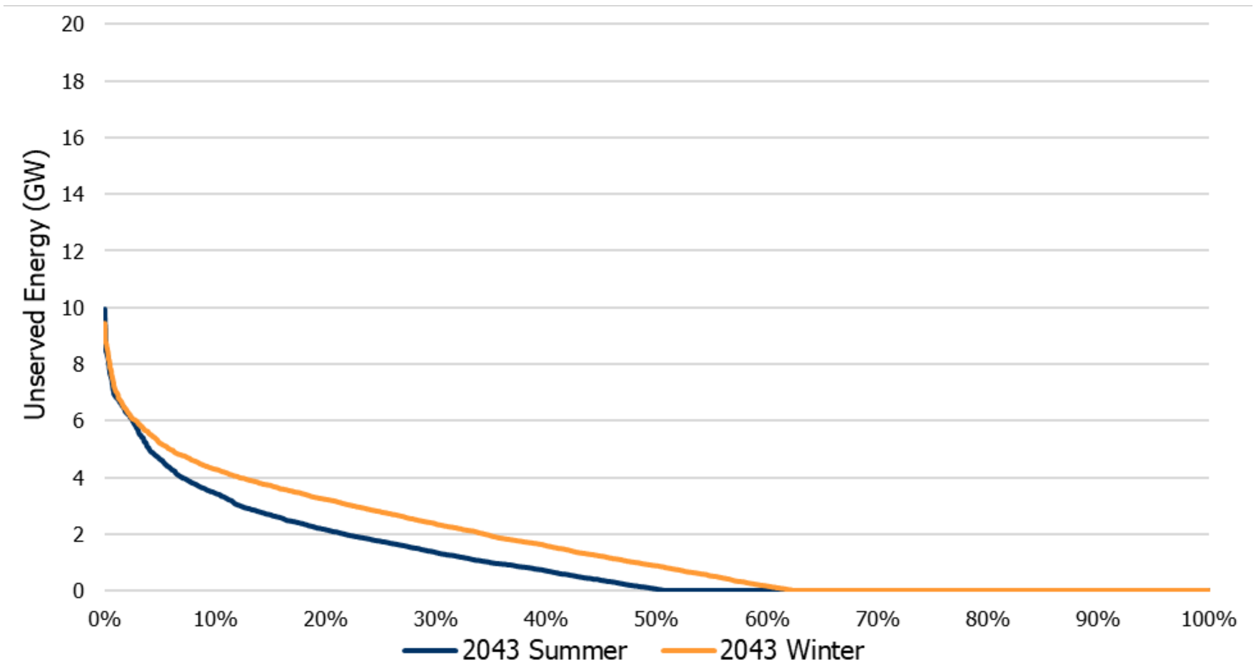



**Figure 30 | Unserved Energy By Season, Case 2**




Duration curves provide insights at the extremes (i.e., baseload requirements and peaking requirements) and the potential utilization of intermediate resources should they be non-fuel limited; however, to assess the value of less flexible, intermittent resources (wind and solar) and energy-limited resources (storage and, potentially, low-carbon fuels), the timing and magnitude of needs becomes important. By further defining the charateristics of unserved energy, we can better understand how these resources can meet needs and provide value. Figure 31 identifies time-of-use periods. The volumes of unserved energy over these periods and how various resources can meet these needs are discussed below.

**Figure 31 | Time-of-Use Period Definitions**

| Winter | | | Summer | | | Shoulder | |
|---|---|---|---|---|---|---|---|
| On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak |
| December - March | | | June - September | | | April, May, October, November | |
| 7 AM - 11 AM; 5 PM - 8 PM | 11 AM - 5 PM; 8 PM - 11 PM | 11 PM - 7 AM | 11 AM - 5 PM | 7 AM - 11 AM; 5 PM - 11 PM | 11 PM - 7 AM | 7 AM - 11 PM | 11 PM - 7 AM |

A solar resource provides most of its energy during summer on-peak and mid-peak periods, with less energy produced during shoulder mid-peak. It also provides capacity value, but mostly in the summer, with the potential to equate summer and winter peaks to the extent that there is a higher need in the summer.

A wind resource provides energy on average throughout the day, with higher capacity factors overnight and during the winter. It also provides capacity, with a higher contribution in the winter, and the potential to equate winter and summer peaks to the extent that there is a higher need in the winter.

Unlike traditional generators, an energy storage system is used to move energy around. A storage resource with limited duration will likely only produce on-peak, with value diminishing as on-peak and mid-peak periods equalize. The ability to charge is also important, and will become a challenge with significant amounts of unserved energy off-peak.

A hydroelectric resource provides energy on average throughout the day, with higher capacity factors during spring freshet in the shoulder periods. During the spring freshet, when the snowcap melts and spring rains cause river levels to rise, many hydroelectric plants run every hour. While the run of river hydroelectric production is quite even for all time-of-use (TOU) periods, peaking hydroelectric production targets on-peak and mid-peak periods.

A nuclear resource provides energy on average throughout the day, with higher capacity factors during the summer and winter, as planned outages are likely to happen in the shoulder periods.

The following figures illustrate the unserved energy using TOU periods for select years (2024, 2034 and 2043). This illustrates the trends of when unserved energy begins to intensify and by what amount, and provides insights on resource opportunities to meet these requirements.

Figure 32 and Figure 33 show the total unserved energy for Case 1 and Case 2, respectively. Of the total, most of that unserved energy is during off-peak and mid-peak hours. However, it is important to note that the TOU periods are not of equal size – that is, they do not contain the same number of hours.

### Figure 32 | Total GWh Unserved Energy by TOU periods, Case 1

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Sum |
| 2024 | 1 | 1 | 0 | 1 | 1 | 2 | 3 | 3 | 14 |
| 2034 | 3,801 | 4,799 | 7,766 | 3,571 | 5,632 | 6,159 | 6,247 | 4,556 | 42,531 |
| 2043 | 6,882 | 9,115 | 16,253 | 5,779 | 9,341 | 11,920 | 12,825 | 12,268 | 84,383 |

### Figure 33 | Total GWh Unserved Energy by TOU periods, Case 2

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Sum |
| 2024 | 3 | 3 | 1 | 2 | 1 | 1 | 0 | 1 | 12 |
| 2034 | 124 | 35 | 807 | 274 | 456 | 489 | 478 | 389 | 3,052 |
| 2043 | 1,188 | 954 | 2,042 | 1,143 | 1,003 | 1,535 | 2,816 | 1,076 | 11,757 |

Figure 34 and Figure 35 show the average unserved energy by TOU period (total energy not served / total number of hours in that period) for Case 1 and Case 2, respectively. In Case 1, unserved energy, on average, is observed over the summer, winter and shoulder period in all TOU periods by 2043. In Case 2, unserved energy, on average, is observed mostly over summer and winter by 2043.

### Figure 34 | Average GWh Unserved Energy by TOU periods, Case 1

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Average |
| 2024 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2034 | 6.3 | 6.2 | 5.1 | 6.8 | 6.5 | 4.0 | 4.5 | 3.0 | 4.9 |
| 2043 | 11.3 | 11.6 | 10.7 | 10.9 | 10.6 | 7.8 | 9.3 | 7.9 | 9.6 |

### Figure 35 | Average GWh Unserved Energy by TOU periods, Case 2

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Average |
| 2024 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2034 | 0.6 | 0.6 | 0.3 | 0.9 | 0.9 | 0.2 | 0.1 | 0.0 | 0.3 |
| 2043 | 1.8 | 2.0 | 1.9 | 1.9 | 2.3 | 0.8 | 0.9 | 0.6 | 1.3 |

Figure 36 and Figure 37 show the maximum unserved energy for Case 1 and Case 2, respectively. These figures complement the peak insights from the duration curves discussed above. In both cases, maximum unserved energy is consistent across all periods, not just peak periods, by 2043, due to outages, resource availability and other factors. This presents a challenge for intermittent (e.g., solar) and energy-limited resources with the ability to target peak periods only, lowering their marginal capacity value.

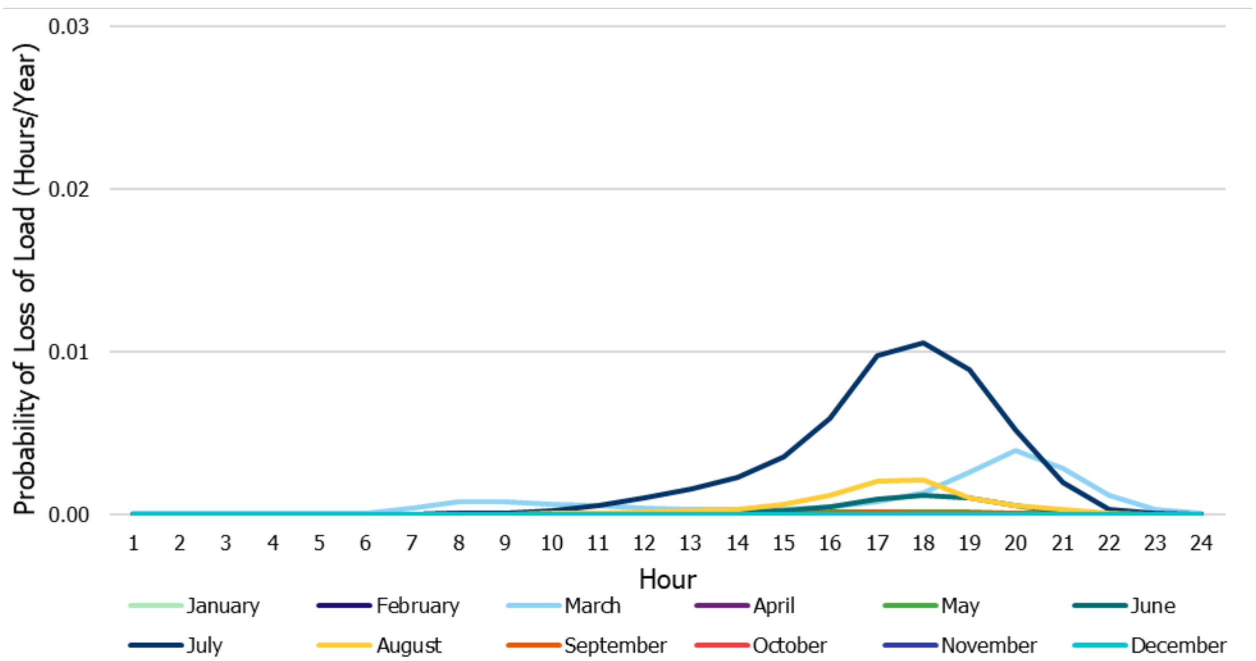
**Figure 36 | Max GWh Unserved Energy by TOU periods, Case 1**

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Max |
| 2024 | 0.7 | 0.6 | 0.7 | 0.4 | 0.5 | 0.4 | 1.2 | 1.5 | 1.5 |
| 2034 | 10.8 | 10.8 | 10.4 | 10.6 | 11.1 | 10.4 | 8.7 | 7.2 | 11.1 |
| 2043 | 16.4 | 16.7 | 14.0 | 15.4 | 17.4 | 16.9 | 15.0 | 14.1 | 17.4 |

**Figure 37 | Max GWh Unserved Energy by TOU periods, Case 2**

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Max |
| 2024 | 0.3 | 0.4 | 0.3 | 0.7 | 0.5 | 0.7 | 1.2 | 1.6 | 1.6 |
| 2034 | 4.6 | 5.9 | 5.2 | 3.9 | 5.7 | 4.3 | 3.1 | 2.0 | 5.9 |
| 2043 | 7.8 | 9.5 | 8.8 | 7.6 | 10.0 | 7.8 | 7.6 | 6.5 | 10.0 |

**Figure 38 | Hourly Probability of Loss of Load, 2027**




To further understand the characteristics of system needs, and the types of resources that can meet these needs, the hourly probability of loss of load was analyzed for select years (2027 and 2029). Given the hourly load forecast and the available resources at each hour, the probability of loss of load is different for every hour. If the system's reserve margin falls below zero in a particular hour, then loss of load is certain.

In its probabilistic assessment, the IESO has analyzed hundreds of simulations at different load levels to determine a metric that best represents the probability of loss of load at every hour of the year. Figure 38 outlines the described metric at every hour of the day for each month in 2027 against the reference demand forecast and a supply outlook, assuming existing resources are available post-contract expiry (i.e., Case 2). Summer months such as July and August exhibit a higher probability of need during hours 16-22, while in winter, there is a small spike around hours 9-10 and then a larger need during hours 17-23. In Ontario, summer months constitute most of the hourly needs given that the system is currently summer peaking; however, the shape of the hourly profiles changes from year to year and is impacted by factors such as the demand forecast, load forecast uncertainty, supply forecast, outages and transmission constraints.

Figure 39 shows the probability of loss of load in 2029 in a similar manner.

**Figure 39 | Hourly Probability of Loss of Load, 2029**

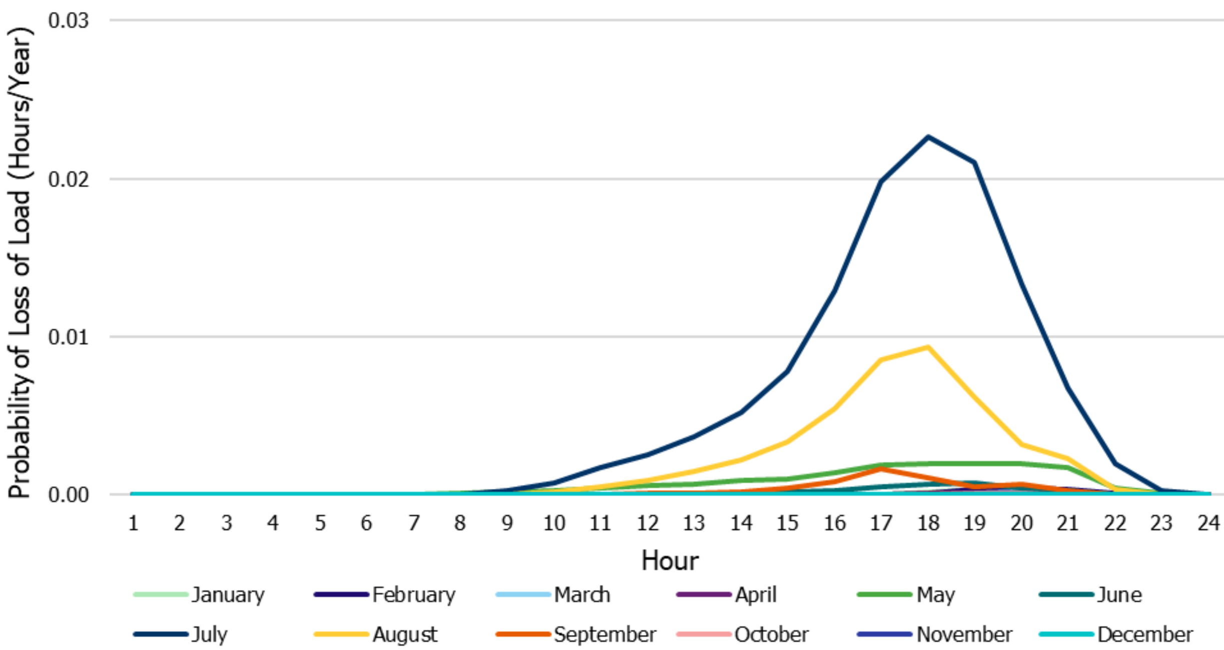
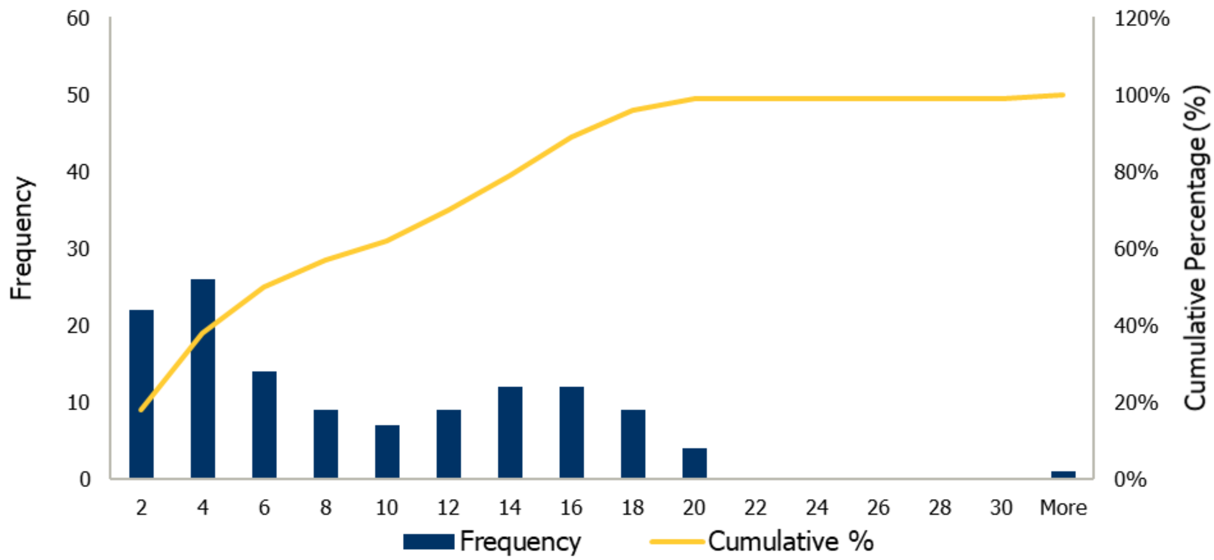


**Figure 40 | Duration of Resource Adequacy Risks Periods, 2027**



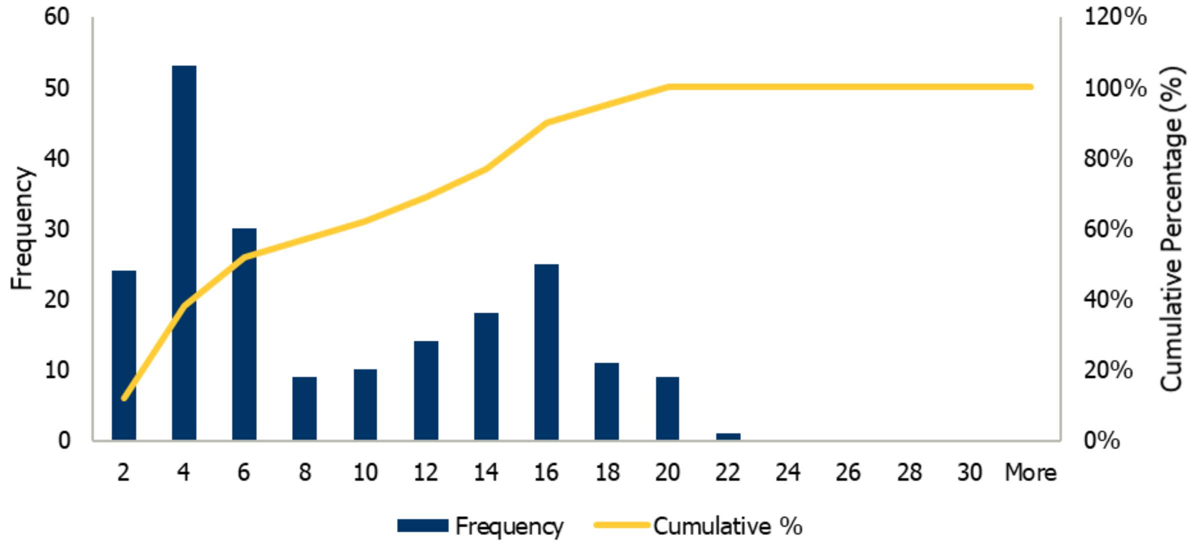

The periods of resource adequacy risk identified in this report tend to be sustained for multiple, consecutive hours. Figure 40 shows the duration of risk periods in 2027. This assessment shows that the length of risk periods can vary greatly.

Looking at the entire range of outcomes observed in the IESO's probabilistic assessments can inform future procurements on the value of resources that are capable of providing energy for a sustained period of time, particularly in preparation for the potential for severe weather conditions:

- 40 per cent of events persist for up to four hours;
- 20 per cent of events persist for more than 4 and up to 8 hours;
- 30 per cent of events persist for more than 8 and up to 16 hours; and
- 10 per cent of events persist for more than 16 hours.

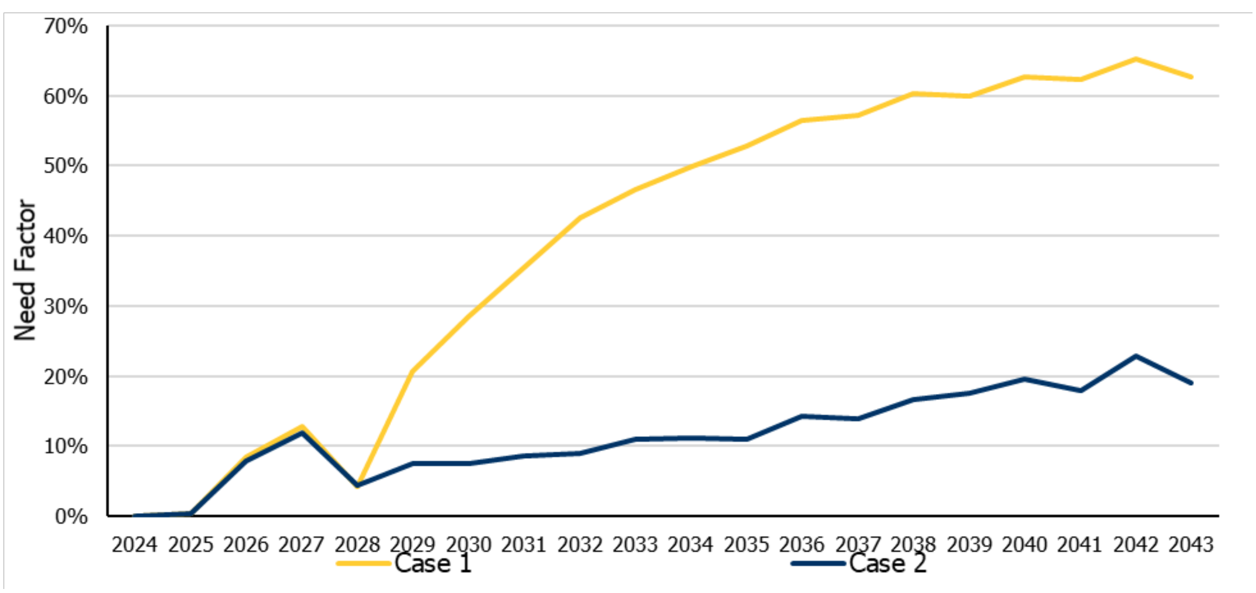
The same technology upgrades, expedited LT1 and LT1 RFPs are designed to run for a minimum of four continuous hours, and are encouraged to generate for longer durations, to address these needs. Figure 41 shows the duration of risk periods in 2029 in a similar manner. As capacity and energy needs increase in the long term, the frequency of longer-duration events increases as well. For example, this analysis shows that the number of events with a duration of 10 hours or more almost doubles in 2029 compared with 2027.

**Figure 41 | Duration of Resource Adequacy Risks Periods, 2029**




Combining capacity and energy needs, Figure 42 shows the need factor of the unserved energy, which becomes more prominent starting in 2029. By the end of the planning horizon, in Case 2, the need factor increases to about 20 per cent. In Case 1, where existing resources are assumed not to be available post-contract/-commitment expiry, the need factor is much higher, at about 60 per cent, illustrating that incremental requirements, and replacement requirements for resources that may not be available post-contract expiry, are for baseload resources in the longer term.

**Figure 42 | Capacity Factor of Need Requirements**



## 7.2 Transmission System and Locational Capacity Needs

Section 5 outlined future system issues arising from limitations of the bulk transmission system to reliably supply forecast demand, along with asset end-of-life considerations.

The 2021 APO also reported on locational requirements, identifying areas where capacity is forecasted to be needed to meet local reliability requirements. For the most part, these locational capacity requirements have not changed over the last year, since the demand, resource mix and transmission system have not changed materially since the studies were carried out. However, planning recommendations for system reinforcements have since been made that will address some locational needs. As well, the outcomes of procurements that are underway are expected to bring additional resources that will change the outlook for local capacity needs.

In this section, the issues outlined in Section 5, in combination with insights from community and customer engagements, regional planning, bulk system studies and IESO operational experience were taken into account in updating the local capacity requirements and in proposing a Schedule of Planning Activities that outlines where and when further bulk system planning will be initiated to address future system issues. These determinations were made in a triaging process that reviewed all known system issues; this process is summarized in Section 7.2.1. Section 7.2.2 reviews where local capacity is needed and Section 7.2.3 provides a table which specifies the local capacity needs; Section 7.2.4 contains the proposed IESO Schedule of Planning Activities.

#### 7.2.1.1. Triaging Approach

The issues were screened according to a number of factors to determine which ones should be addressed by acquiring capacity in specific areas, and which ones should be addressed through further planning. All of the issues were reviewed together to assess whether logical groupings can be formed in order to seek common and/or integrated solutions that address the resulting "bundle" of issues. Issues may be bundled together based on factors such as common drivers, time frames, affected infrastructure, geographic proximity and the IESO's professional judgement, based on system knowledge and experience.

Next, these logical groupings were screened according to timing – i.e., whether the time until the need emerges will permit a bulk planning study to be carried out and implement solutions – as well as market insights about the viability of resource options alone versus the potential for transmission solutions to deliver ratepayer value. In addition, the nature of the issue (and/or bundle of issues) was a factor. The outcomes of the triaging are described in Section 7.2.2 and 7.2.3.

#### 7.2.1.2. Areas Where Local Capacity is Needed

This section identifies the areas in the province where the IESO is recommending that local capacity be acquired. These requirements for local capacity can be zonal, sub-zonal (i.e., representing an area within a zone), or comprise multiple zones.

It is important to note that the purpose of these requirements for local capacity is to maintain local area reliability. This is different from the IESO deliverability studies being coordinated with the RFPs that are underway, and from the zonal maximums provided for the IESO's Capacity Auctions, the purpose of which is to ensure that transmission limitations do not prevent the capacity acquired in these procurements from contributing to provincial resource adequacy. This APO provides the former requirements (i.e., areas in the province where capacity is needed for local reliability), while the latter restrictions (i.e., where resources can and cannot connect to meet provincial adequacy needs) will be provided in coordination with the relevant acquisition processes.

### West of London/West of Chatham Areas

As identified in the 2021 West of London bulk planning study,[24] forecasted demand growth in the IESO West electrical zone (southwestern Ontario), after considering the transfer capability of the Buchanan-Longwood/Negative Buchanan-Longwood (BLIP/NBLIP) transmission interface, creates a locational capacity requirement in the West of London area beginning in 2030. Part of this locational requirement is more specifically constrained within the area West of Chatham. The total locational capacity requirement West of London grows to 1,975 MW by 2035, of which 550 MW is in the Windsor-Essex and Chatham-Kent areas further west closer to the greenhouse loads (i.e., West of Chatham). This need, which does not assume continued availability of resources after their contracts expire, will be reassessed following the conclusion of the Long-Term 1 RFP. The recontracting of generation in Sarnia until May 2031 will shift the West of London need out by a year, but will not materially change the overall need by 2035, nor the West of Chatham need. A recently announced focus on energy efficiency targeted specifically at greenhouses could also alleviate this need.

### East of the "Flow East Towards Toronto" (FETT) Interface

The 2021 APO identified a significant capacity requirement east of the FETT interface. The area east of FETT includes the Toronto, Essa, East, Ottawa, Northeast and Northwest[25] electrical zones. While this APO study assumes the retirement of Pickering NGS, its proposed nine-month extension to September 2026, if approved by regulators, could address the capacity need forecasted to occur in 2026. In the longer term, a capacity requirement east of FETT is expected to emerge by the end of the decade; however, the timing and magnitude of this requirement will need to be re-assessed following the conclusion of the Long-Term 1 RFP.

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[24] "Need for Bulk System Reinforcements West of London" https://www.ieso.ca/en/Get-Involved/Regional-Planning/Southwest-Ontario/Southwest-Ontario-Bulk-Planning-Initiatives

[25] The amount of new capacity in the northwest to address this need would be limited by transmission system capability.

Within the area east of FETT, a more localized capacity gap is forecasted to emerge within the GTA beginning in about 2027 and growing until the end of the APO planning horizon. Given that this issue affects several autotransformers supplying the load centre and is linked with other initiatives, such as the Northwest GTA Transmission Corridor Study,[26] focused bulk transmission system planning is warranted. However, any resources that are sited in the GTA, as well as energy efficiency or demand management, will also help to push back the need while helping to alleviate the need east of FETT.

**Ottawa Area**

The 2021 APO identified a localized capacity requirement in the Ottawa electrical zone beginning in 2027. The transmission recommendations in the IESO's Gatineau Corridor End-of-Life Study, when implemented, will push this need back to the mid-2030s, under the current demand forecast. Additional targeted energy efficiency in the region, as recommended in the study, could defer this need to beyond the APO planning horizon. The IESO will continue to monitor growth in the area, and will trigger additional studies when needed.

**Northern/Northeastern Ontario**

The capacity requirement in northern Ontario to the west of the Mississagi Flow West interface will be addressed by the bulk transmission system upgrades that were recommended in the Northeast Bulk System Plan.[27] These upgrades will also address needs being driven by new mining loads north of Sudbury. As plans and policies unfold that influence the development of hydroelectric resources in northern Ontario, planning may be required to determine options for the connection of these resources to the provincial grid and ensuring their deliverability to meet system capacity and energy needs.

#### 7.2.1.3. Summary of Locational Capacity Needs

Given the needs identified in the preceding section, and accounting for changes since 2021, the locational capacity needs remaining in Ontario are summarized in Table 4.

**Table 4 | Locational Capacity Needs**

| Location | Start of Need | Total Capacity Requirement |
|---|---|---|
| West of Chatham | 2030 | 550 MW by 2035 |
| West of London | 2031 | 1,425 MW by 2035 |
| East of FETT | 2029 | 9,000 MW by 2042 (increases with demand growth) |

[26] This study is being undertaken jointly between the IESO and Ontario's Ministry of Energy to identify and seek to protect a corridor of land for future high-voltage transmission to supply urban expansion in the northwest GTA.

[27] https://www.ieso.ca/en/Get-Involved/Regional-Planning/Northeast-Ontario/Bulk-Planning

#### 7.2.1.4. Schedule of Planning Activities

The triaging exercise informed a Schedule of Planning Activities (SOPA) (see Table 5) that lists the bulk planning studies that will be needed to address system issues. These plans are geared toward the issues that warrant an evaluation of transmission alternatives, and where there is time to carry out a study and still implement solutions. This would typically include system issues that emerge more than five years in the future. Bulk planning studies may recommend transmission solutions, and/or recommend acquire resources in specific areas. Multiple alternatives comprising a portfolio of solutions may also be recommended.

The Schedule of Planning Activities is intended to provide a transparent snapshot of the IESO's bulk system planning workplan covering the next three to five years. As conditions evolve and the generation outlook or demand forecast changes, the need and timing for bulk studies may be re-assessed. These changes will be reported in subsequent APOs.

**Table 5 | Schedule of Planning Activities**

| Location/Study Name | Start Year | Comments |
|---|---|---|
| Northeast Ontario Voltage Study | 2022 | This study is being conducted as a follow-up to the Northeast Bulk System Plan, to assess and recommend solutions to potential high voltage issues that could result from the planned expansion of the bulk transmission system in northern Ontario. This study is already underway. |
| GTA Bulk Supply Study | 2023 | Review capability of the bulk power system to deliver sufficient power into the GTA load centre; study integrated alternatives coordinated with Integrated Regional Resource Plans in Toronto and York Region; address reactive power requirements in the area post-Pickering shutdown. |
| Lennox–St. Lawrence Area Study | 2023 | The need to study bulk system options is being driven by the end-of-life of key transmission facilities, and there is an opportunity to address several other system and operability concerns in the area through an integrated study. |
| Ontario–Manitoba Interconnection Study | 2023 | A joint Ontario/Manitoba/Minnesota interconnection study will examine potential system reliability impacts of long duration outages to intertie equipment and develop a plan to address the end of life of critical equipment. |

| Location/Study Name | Start Year | Comments |
|---|---|---|
| Essa Area/Flow North and Flow South Interface Study | 2024 | Review the capability of the Essa autotransformers and bulk system in the area to supply demand growth; and review the capability of the Flow South, Flow North and CLAN interfaces given changing load patterns and bulk system enhancements in northern Ontario. |
| Central-West Ontario Bulk Study | 2024 | This study is tentatively scheduled to begin in 2024. This would follow the next scheduled regional planning cycle for the Burlington to Nanticoke region; it would also be prudent to wait for greater certainty on the location of prospective large industrial loads in the area, as well as any new generation resources. |
| Northern Ontario (Hydroelectric Interconnection Study) | TBD | Depending on decisions related to the development of new hydroelectric resources in northern Ontario, further bulk system studies may be needed to assess potential bulk system impacts and deliverability of these resources. |

# 8 Outcomes and Other Considerations

The energy production outlook, which includes interconnections with neighbouring jurisdictions, illustrates that even with the possibility of imports, Ontario could begin seeing energy shortfalls in the 2030s if existing resources do not remain available after their current commitments end. As a result of rising demand and increasingly tight system conditions, imports, marginal costs, and system emissions are all expected to increase throughout the 2020s.

## 8.1 Provincial Energy Production Outlook

The IESO-administered energy markets are linked to Ontario's neighbours through interconnections[28]. Imports and exports are scheduled in the real-time energy market to take advantage of price differences between jurisdictions. In 2021, Ontario imported 8.7 TWh of energy and exported 17.2 TWh.

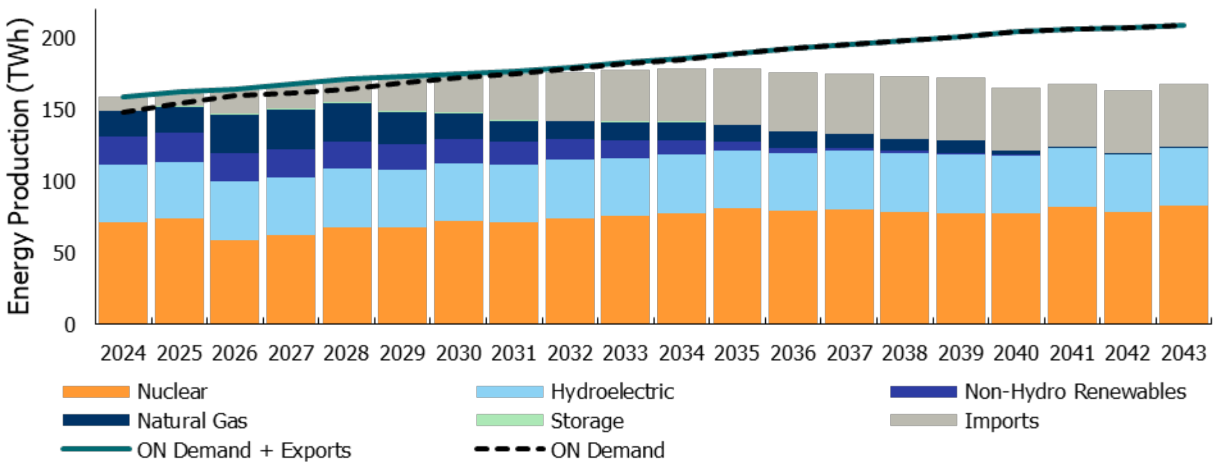
Unlike energy adequacy, the energy production outlook includes interconnections with Ontario's trading partners to more closely represent expected conditions and market outcomes. Although trade with our neighbours will help to allow us to meet energy requirements toward the end of the outlook period, Ontario becomes energy inadequate without existing resources, as shown in Figure 43. Figure 44 shows the energy production outlooks with continued availability of existing resources.

**An Important Note on Uncertainty in Plan Outcomes**

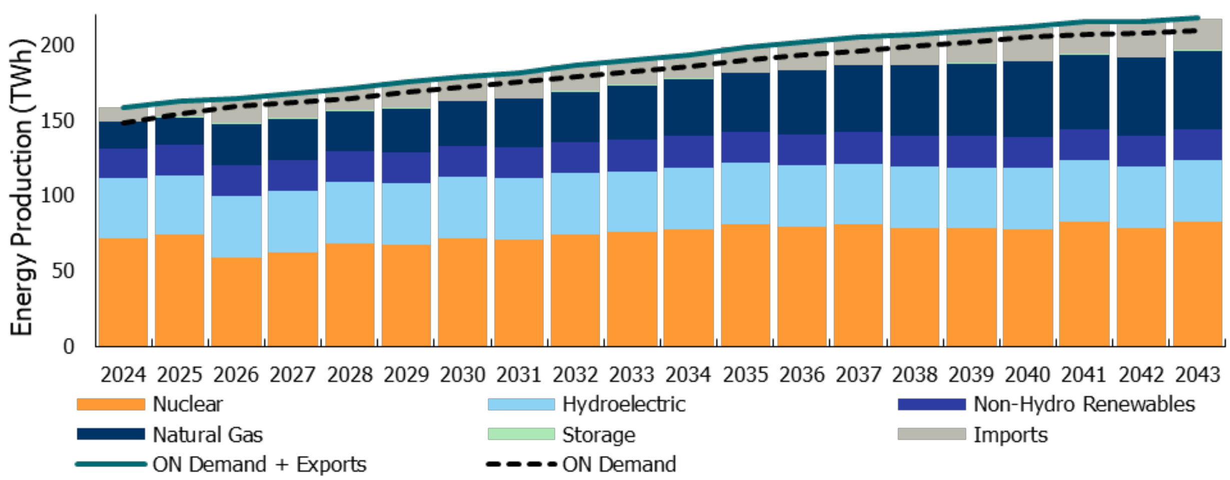
Ontario is currently energy adequate under both Case 1 and Case 2 up to and including 2028. Beyond 2028, the system will require new resources which could have varied impacts on imports, exports, marginal costs, and emissions. The current forecast relies heavily on existing natural gas and imports for energy adequacy. This is not a likely outcome, but has been included to ensure a consistent 20-year outlook across the entire report and for illustrative purposes. Actual outcomes will depend on future procurements, which are expected to secure a diversity of supply. As such, the forecasts that follow are speculative beyond 2028, and are for illustrative purposes.

[28] Ontario currently has interconnections with its five neighbours: Quebec, Manitoba, Minnesota, Michigan and New York. More information about imports and exports can be found on the IESO's website.

## Figure 43 | Energy Production Outlook, Case 1



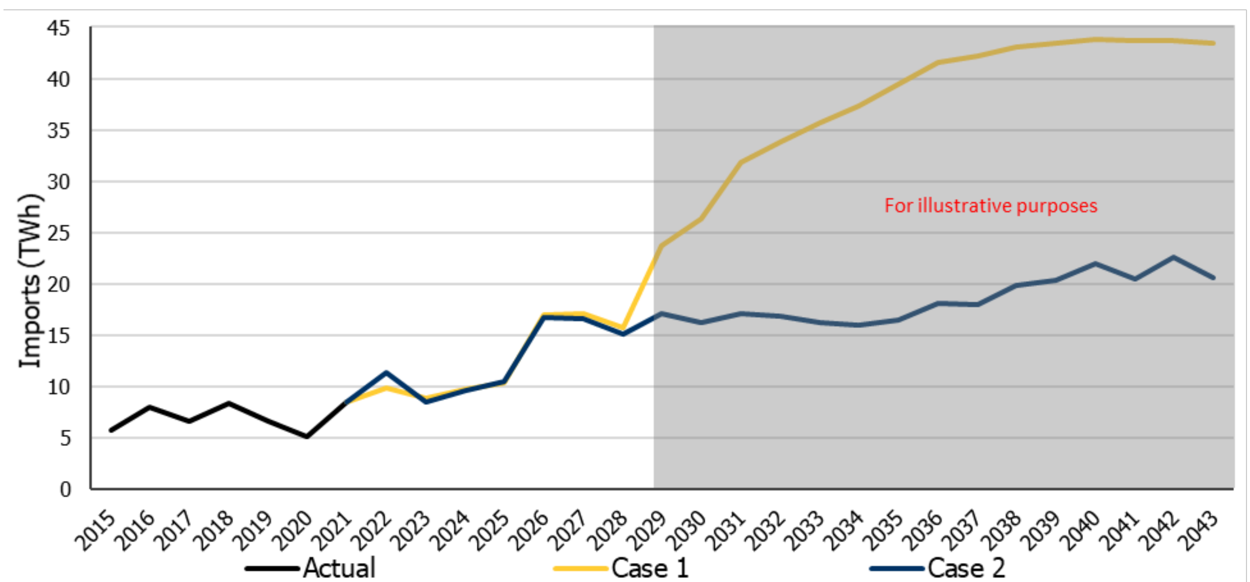

## Figure 44 | Energy Production Outlook, Case 2



Energy production of baseload resources is similar to the energy adequacy outlook because production from baseload resources is generally insensitive to market prices. Gas production, which is often used to ensure power is supplied during times of higher demand and can provide needed flexibility in response to system conditions, can vary depending on when and if these resources are more economic than imports in the real-time market. In addition, where opportunities exist, energy from Ontario's electricity fleet can be exported. Evolving decarbonization policies are expected to change supply mixes, and therefore the energy production outlook, in both Ontario and its neighbouring jurisdictions; the impacts of these changes will be reflected in future work as more information becomes available.

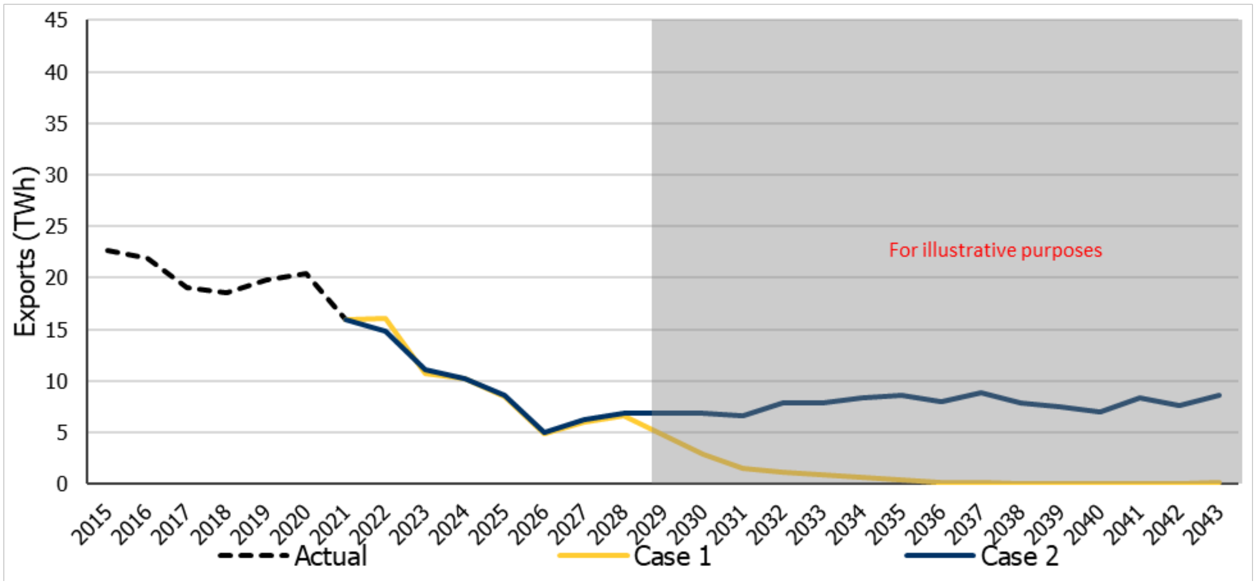
In Figure 45, imports increase from historic levels (about 6 to 8 TWh) in both scenarios. Historically, Ontario has been a net energy exporter. In the scenario that assumes continued availability of resources, Ontario becomes a net energy importer starting in the mid-2020s as the demand forecast increases. In Case 1, imports reach about 16 TWh by the end of 2028 as demand increases, and existing resources start to retire. In Figure 46, energy exports decrease in the early and mid-2020s with nuclear retirements and refurbishments. In Case 1, exports begin to decrease around 2028, while in Case 2, exports remain fairly consistent. While the assumptions underpinning this outlook point to Ontario becoming a net importer of energy, many factors could change this outcome, including the nature of any new capacity that may be built in Ontario, the considerations of increased intertie capability and developments in the electricity sectors of neighbouring jurisdictions as their systems evolve.

**Figure 45 | Energy Production Outlook, Imports[29]**




[29] For 2022, the 2020 APO forecast values are shown. For 2023, the 2021 APO forecast values are shown

**Figure 46 | Energy Production Outlook, Exports**




## 8.2 Fleet Utilization and Marginal Resources

Long-term power system plans use an economic dispatch model that schedules resources to meet system needs based on the lowest cost. This model considers each resource's production and variable costs, which typically include fuel and variable operation and maintenance costs.

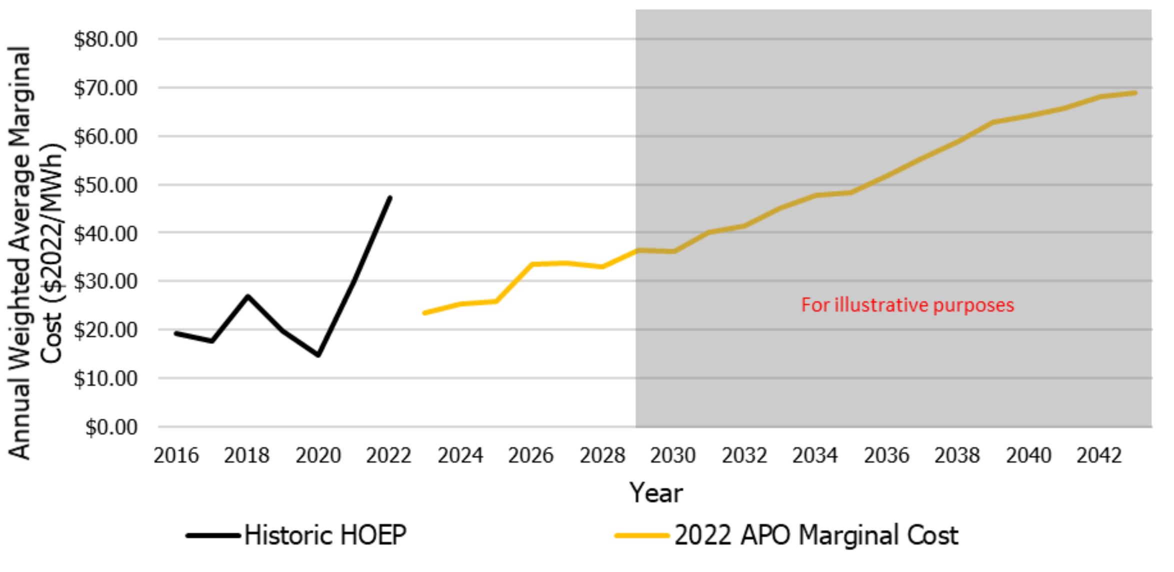
Supply resources are categorized as baseload (operating essentially constantly – e.g., nuclear), dispatchable (operating as needed – e.g., gas), or intermittent (operating when fuel is available – e.g., solar or wind). Usually, baseload and intermittent resources have lower marginal energy costs than dispatchable resources.

Resources are generally dispatched from lowest-production-cost baseload to higher-production-cost dispatchable. The marginal resource is the one that provides the last unit of energy needed on the system, and is the most expensive resource scheduled. During the peak demand hours of hot summer days, the marginal resource is typically a natural gas–fired generator; overnight during autumn, gas-fired generation is less likely to be the marginal resource.

The data underpinning this outlook are based on an economic dispatch model that simulates each hour of the outlook period. This model dispatches units in order of their production costs and identifies the marginal resource in each hour. The marginal cost in each hour is the production cost of the marginal resource. For this analysis, there has been a change in the methodology to rely on the existing supply mix, resulting in unserved energy due to the existing fleet not being sufficient to meet energy demands without incremental resources. In general, the marginal costs provide the trajectory of market prices, which can differ widely due to market participant behaviour, congestion, the supply mix, the variable input cost for fuel and other factors.

Figure 47 illustrates the weighted average marginal costs forecast and the historical Hourly Ontario Energy Price (HOEP). Only Case 2 is considered, as it provides a more complete resource picture over the planning horizon. The marginal costs rise in the immediate future is due to an increase in gas facilities becoming the marginal resource.

**Figure 47 | Weighted Average Marginal Costs Forecast and Historical HOEP[30]**




[30] 2021 actual HOEP is year-to-date as of December 7, 2021.

## 8.3 Greenhouse Gas Emissions

As noted above, Ontario is substantially energy adequate up to 2028. Resources will need to be added past this time, which could significantly impact this emissions outlook. Actual emissions will depend on future procurement outcomes, and a diversity of supply is expected to be procured. See the IESO's Pathways to Decarbonization report to learn more about how emissions may be reduced in the years ahead.

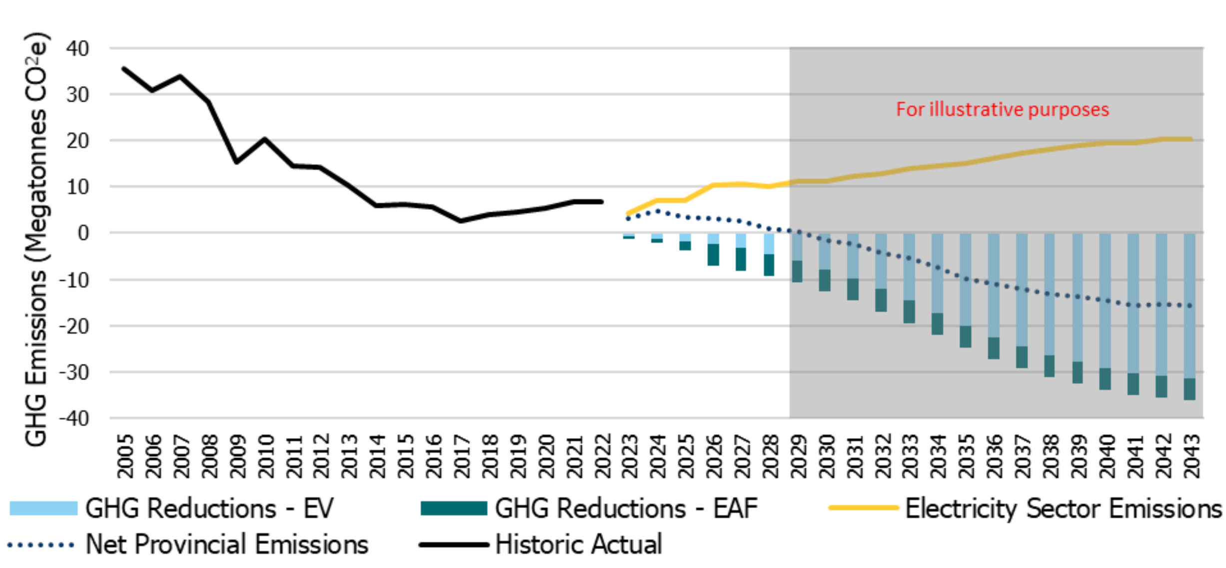
Electricity sector emissions are forecast to increase to over 10 Mt CO2e by 2028 due to reduced nuclear production and growing demand, resulting in increased production from gas-fired generation, as shown in Figure 48.

An increase in electricity sector emissions does not necessarily mean an increase in economy-wide emissions. The carbon intensity of electricity remains far below that of other fuels, such as gasoline for automotive transportation or fuel oil for space heating. Switching from higher-emission fuels to low-carbon electricity could increase electricity sector emissions while reducing province-wide emissions. As electricity consumption increases, the attendant rise in electricity sector emissions could be reduced by increased energy efficiency, improved management of peak demand or the entry of non-emitting resources to the Ontario market.

Figure 48 shows both historical and forecast electricity sector GHG emissions, as well as estimated GHG emissions reductions in the broader economy due to two major electrification elements in the APO reference demand forecast: EVs and a number of industrial electrification initiatives. Figure 48 also shows Ontario's net emissions resulting from activity in the electricity sector (i.e., electricity sector emissions, less emissions avoided due to electrification). Note that emissions reductions shown here are an estimate only and are presented for purely illustrative purposes. Further details can be found in the methodology and data tables.

Further electrification elements in the greater economy will reduce GHG emissions over time, but not all are considered in the APO. For example, electrified rail, individual industrial facilities, home heating, etc., will all contribute to further GHG reductions in the greater economy, but actual reductions cannot be accurately quantified without more information. Overall, EVs are expected to account for the greatest amount of GHG reductions, overshadowing all other elements regardless of whether they are quantified in the APO.

**Figure 48 | Electricity Sector GHG Emissions, Historical and Forecast**

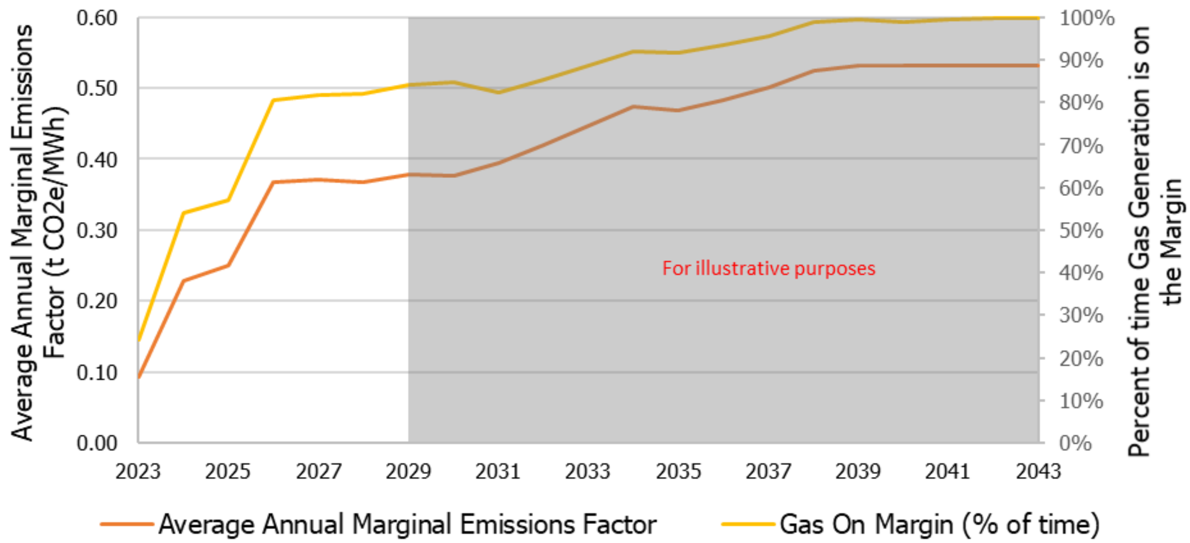



## 8.4 Marginal Emissions

As discussed above, the last resource selected to meet demand is considered the marginal resource, which then sets the marginal price. This marginal resource is an indicator of the potential GHG impact of increasing demand, considering it is expected that gas resources will continue to be the marginal resource more often in the future. Figure 49 shows the percentage of time gas is on the margin year-to-year, as well as the annual emissions factor.

The escalating trend continues quickly prior to 2028 as demand grows and other resources come out of service, as natural gas facilities will increasingly be the marginal resource. This will result in continuously higher average annual marginal emissions factors. If the future supply mix varies from the assumed existing supply mix, the emission levels and annual average emission rates could be lower.

**Figure 49 | Marginal Emissions Factors**




## 8.5 Carbon Pricing

Currently, the electricity sectors in Ontario and in neighbouring jurisdictions are subject to carbon pricing. The carbon pricing assumptions used in this outlook are based on the provincial Emissions Performance Standards (EPS) program, and assume that the price of carbon in Canada will rise to $170/t $CO_2e$ by 2030 and remain at that level for the duration of the planning period.[31] Details on carbon pricing policies currently in effect within the northeastern portion of the Eastern Interconnection, and how carbon pricing was modelled for this outlook, can be found in the Carbon Pricing Module.

[31] See https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html

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